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THE UNIVERSITY OF ALBERTA

PERFORMANCE OF THE IMMISCIBLE CARBON DIOXIDE WAG PROCESS AT LOW PRESSURE

BY

STEVEN BLAIR DYER

©

A THESIS
SUBMITTED TO THE FACULTY OF GRADUATE STUDIES AND RESEARCH
IN PARTIAL FULFILMENT OF THE REQUIREMENTS FOR THE DEGREE
OF MASTER OF SCIENCE
IN
PETROLEUM ENGINEERING

DEPARTMENT OF MINING, METALLURGICAL AND PETROLEUM
ENGINEERING

EDMONTON, ALBERTA
SPRING, 1989

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(SIGNED) S Dyer

PERMANENT ADDRESS:
12524 - 42nd Avenue
Edmonton, Alberta, Canada
T6J OX3

DATED: MARCH 15th, 1989

THE UNIVERSITY OF ALBERTA

FACULTY OF GRADUATE STUDIES AND RESEARCH

The undersigned certify that they have read and recommend to the Faculty of Graduate Studies and Research, for acceptance, a thesis entitled "PERFORMANCE OF THE IMMISCIBLE CARBON DIOXIDE WAG PROCESS AT LOW PRESSURE" submitted by STEVEN BLAIR DYER in partial fulfilment of the requirements for the degree of MASTER OF SCIENCE in PETROLEUM ENGINEERING.

S.M. Farouq Ali (Supervisor)

J.M. Whiting

Masliyah

J.H. Masliyah

W.S. Tortike

DATED: MARCH 15th, 1989

To My Wife Tracy,
to My Mom and Dad,
For Their Love, Support, and Faith
in my abilities

Abstract

The immiscible carbon dioxide process, in the water-alternating-gas (WAG) mode, holds considerable promise for the recovery of moderately viscous oils, where the reservoir conditions are unsuitable for the application of thermal recovery methods.

A new experimental linear model was designed to scale some of the aspects of a larger two-dimensional model. This model makes it possible to carry out experiments in a considerably shorter time span than for the larger model. It also attempts to eliminate sweep effects so that displacement efficiency and mobilization efficiency may be studied more closely.

An experimental program was conducted in an attempt to quantify the mechanisms involved in the immiscible displacement of heavy oil by carbon dioxide WAG process at a low pressure.

The effect of low pressure, WAG ratio-slug size combinations, and the number of slugs into which the carbon dioxide and water are split, were examined. It was found that splitting the slug into five rather than ten slugs, was almost equally effective from the point of view of oil recovery, and that, in certain cases, a significant increase in oil recovery was achieved over the single slug process.

Recovery efficiency, at low pressure, drops approximately fifteen percentiles as the operating pressure is lowered from 5.5 to 1.0 MPa for an equal mass of carbon dioxide injected. When an equivalent volume of carbon dioxide is injected, oil recovery drops approximately five percentiles over the same operating pressure variation.

Low velocity displacements tended to increase gravity override and oil recovery was reduced. High WAG ratio runs resulted in early water breakthrough and high cumulative water-oil ratios. Tertiary displacement of heavy oil does not appear to be an effective use of the immiscible carbon dioxide flooding process.

Acknowledgements

The author expresses deepest gratitude and appreciation to Dr. S.M. Farouq Ali for his guidance and support throughout this investigation. The author feels he has gained a friend and is a better person because of his association with Dr. S.M. Farouq Ali.

Appreciation is also expressed to Mr. Bob Smith and the rest of the technical staff of the Department of Mining, Metallurgical, and Petroleum Engineering for their help and expertise in setting up the laboratory equipment.

Thanks to W.S. Tortike for making available his graph digitizing software for the Macintosh®, DigiGraf, and to Sara Thomas for her input and patience with my writing skills.

The financial support for this research provided by the Alberta Oil Sands Technology and Research Authority (AOSTRA) is gratefully acknowledged. Thanks are expressed to Dr. Karl Miller and Husky Oil Operations Limited for providing the fluids and sand for some of the experiments.

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Nomenclature

g	gravity acceleration constant	[m/s^2]
k	absolute permeability	[m^2]
k_r	relative permeability	[dimensionless]
p	pressure	[MPa]
B	formation volume factor	[sm^3/m^3]
D	coefficient of diffusivity	[cm^2/s]
E	efficiency	[%]
H	system height	[cm]
HCPV	hydrocarbon pore volume	[cm^3]
ISUF	in-situ CO_2 utilization factor	[fraction]
J	Leverett J-function	[dimensionless]
L	system length	[cm]
M	mobility Ratio	[dimensionless]
N_c	capillary number	[dimensionless]
N_{cyc}	number of cycles	[−]
PV	pore volume	[cm^3]
Req	CO_2-requirement	[sm^3/sm^3]
Ret	CO_2-retention	[%inj]
R_s	solubility	[sm^3/sm^3]
S	saturation	[fraction]
S^*	normalized saturation	[dimensionless]
$\overline{S}$	average saturation	[fraction]
T	temperature	[kelvin]
V	volume	[cm^3]
V_{cyc}	volume of CO_2/cycle/pay thickness	[sm^3/m]
W	system width	[cm]
X	mole fraction	[mole%]

Prefix

s	standard conditions	[15.6°C and 0.101 MPa]

Greek

ϕ	porosity	[fraction]
$\mathcal{M}$	morphology factor	[dimensionless]
μ	fluid viscosity	[mPa•s]
ρ	density	[kg-mol/m^3 or g/cc]
σ	interfacial tension	[N/m]
υ	Darcy velocity	[m/s or m/d]

Subscripts

c	critical
d	displacing phase
g	gas phase
i	injection
m	model
o	oil phase
of	final oil
oi	initial oil
orp	residual oil to the process
p	prototype
w	water phase
wc	connate water phase
x,y,z	cartesian coordinate direction

A	areal sweep
D	displacement
LC	linear core model
M	mobilization
R	overall
T	transverse direction
TD	two-dimensional model
V	vertical sweep

Chapter I

Introduction

Many heavy oil reservoirs in Alberta, Saskatchewan, and other areas are not suitable for the application of thermal recovery methods, such as steam injection and in situ combustion. This is primarily due to thin pay sections [<6m], and considerable depths [>1000 m]. Approximately 85% of Saskatchewan's heavy oil formations are less than 10m thick, and often have an underlying water sand. Under these conditions, thermal methods are inefficient and uneconomical due to excessive vertical heat losses and steam scavenging by the bottom water. This provides the motivation for searching an alternative to thermal methods for thin heavy oils.

Laboratory research conducted in the 1950s identified the many aspects of carbon dioxide flooding such as oil swelling, viscosity reduction, miscibility effects, and solution gas drives. In the United States, the use of carbon dioxide in enhanced oil recovery techniques, particularly miscible applications, has grown steadily over the past decade.

Carbon dioxide gas may behave as a miscible or immiscible fluid when contacted with oil at reservoir conditions. Holm[1] defines miscibility as follows: "For petroleum reservoirs, miscibility is defined as that physical condition between two or more fluids that will permit them to mix in all proportions without the existence of an interface. If two, or more, fluid phases form after some amount of one fluid is added to others; the fluids are considered immiscible and an interfacial tension exists between the phases."

Miscible displacement at reservoir conditions is characterized by the minimum miscibility pressure. At sufficiently high pressures, light hydrocarbons [C_5-C_{30}] are extracted from the oil to enrich the carbon dioxide gas phase to such a degree that the composition of the gas at the displacing front becomes miscible with the reservoir oil.

The minimum miscibility pressure increases with: (1) decreasing extractable hydrocarbons [C_5-C_{30}], and (2) increasing temperature.

Moderately viscous heavy oils [10-15°API] lack the necessary extractable hydrocarbons for miscible conditions to be economically attained. In some cases, moderately light oils [25-35°API] are being displaced immiscibly because the pressures required to achieve miscible conditions would severely fracture the formation. Fracturing is undesirable in that it leads to gas channeling and early carbon dioxide breakthrough.

Both laboratory and field studies have been conducted to determine the effectiveness of the immiscible carbon dioxide process. Laboratory studies are used to determine and optimize the recovery process mechanisms. Field studies, both pilot and full scale projects, have been carried out in two modes, namely: primary and tertiary. Primary recovery methods have been the most successful to date while tertiary methods have helped greatly in reducing water and gas cuts in late flood life projects.

The main focus of this research was the quantification of the recovery mechanisms for the low pressure immiscible carbon dioxide water-alternating-gas (WAG) flooding process. Previous investigations concentrated on the high pressure application of immiscible carbon dioxide flooding in a scaled physical model. These studies concluded that the WAG process was best suited for the types of reservoirs under investigation.

Chapter II

Statement of the Problem

The objectives of this study were to review the literature on the technological research being conducted on immiscible carbon dioxide flooding of heavy oil. The review was to include the changes in oil properties due to solution and diffusion of carbon dioxide. Also, the carbon dioxide displacement mechanisms and a study of the past and on going immiscible carbon dioxide field projects was to be carried out. Based upon the foregoing, the following specific objectives were defined:

1a. To design and construct a partially scaled physical model for the following purposes.

   i. To isolate the displacement and mobilization efficiencies by assuming vertical and areal sweep to be equal to unity in a linear core model.

   ii. To use the model as a screening model for the larger, more time-consuming two-dimensional model.

   iii. To simulate the direct line drive flooding pattern.

1b. To design and implement a gas injection and metering system capable of operating at a low pressure with good accuracy.

1c. To write a manual detailing all of the laboratory procedures used in conjunction with the immiscible carbon dioxide flooding facilities at the University of Alberta.

2 To study the efficiency of the immiscible carbon dioxide water-alternating-gas (WAG) process in the context of the following objectives:

- i. To compare WAG type runs with a waterflood to examine the benefits of the EOR process over conventional techniques.
- ii. To evaluate the role of the total slug size and the number of alternating slugs of carbon dioxide and water on the efficiency of the WAG process at low pressure.
- iii. To assess the effect of operating pressure for:
  - a) runs where total CO_2 slug volume, at reservoir conditions, is the same;
  - b) runs where total CO_2 slug mass is the same.
- iv. To assess the effect of WAG ratio for low pressure immiscible CO_2 floods.
- v. To assess the effect of fluid velocity for low pressure immiscible CO_2 WAG floods.
- vi. To examine the effect of oil viscosity for low pressure immiscible CO_2 WAG floods, in the
  - a) secondary recovery mode;
  - b) tertiary recovery mode.

3. To compare the linear core model with the two-dimensional model at several pressures.

4. To evaluate the potential of the process for a candidate reservoir.

Chapter III

Literature Review

This chapter provides an extensive review of the literature describing the various aspects which are considered when studying the immiscible carbon dioxide flooding process.

The first section of the review is a discussion of the transportation mechanisms involved in the mass transfer of carbon dioxide with formation fluids. The next section deals with the effects of carbon dioxide on the formation fluids and the formation itself. Factors which effect recovery efficiency are then discussed to see how the immiscible carbon dioxide flooding process can enhance the recovery of heavy oils. Various carbon dioxide-water strategies are then presented to understand mobility control concepts. Tertiary recovery by immiscible carbon dioxide flooding is then discussed. Scaling and simulation of the immiscible carbon dioxide flooding process are the next two sections reviewed.. Finally, application of the immiscible carbon dioxide flooding process in field projects are reviewed extensively.

Transport of Carbon Dioxide in Heavy Oil and Reservoir Water

How does the carbon dioxide mix with the reservoir fluids, namely: oil and water? Three mass transfer mechanisms are discussed in this section. Solubility is the most important mechanism of carbon dioxide transport in the reservoir. Diffusion and dispersion also affect, to a lesser extent, the transport of carbon dioxide.

Solubility

The most important property of heavy oil-carbon dioxide, systems is carbon dioxide solubility. "Solubility of one substance in another depends fundamentally upon the ease with which the two molecular species are able to mix."[2] Klins[3] stated that for low pressure application [<7 MPa], the major effect would be due to solubility of carbon dioxide in crude oil. The solubility of pure carbon dioxide in Lloydminster Aberfeldy [15-17°API] oil at 5.5 MPa and 20.6°C is approximately 70 sm^3/sm^3 of oil. Solubility is a strong function of pressure and to a lesser degree temperature and oil composition. Solubility increases with pressure and decreases with temperature and reduced API gravity.

Carbon dioxide is more soluble in hydrocarbons as a gas rather than a liquid phase.[1,4,5] Miller and Jones[6], and Briggs and Puttagunta[7], showed that a sharp break occurs on the P-V-T curves at the carbon dioxide condensation pressure. At this point carbon dioxide changes from a gas to a liquid phase. Further increases in pressure beyond this point [≈6.9 MPa & 24°C] result in only small amounts of carbon dioxide liquid dissolving in the crude oil. Figure 3.1 (After Ref. 1) is a comparison of solubility of carbon dioxide in Wilmington [17°API] oil with Lloydminster Aberfeldy [15°API] oil and illustrates the condensation break point. Beeson and Ortloff[8] conducted displacement experiments using carbon dioxide. They found that higher oil recoveries were obtained when an equal mass of carbon dioxide, driven by water, was injected as a gas rather than a liquid.

In 1926, Beecher and Parkhurst[9] found that carbon dioxide was more soluble, on a molar basis, in a 30.2°API oil than air and natural gas [CH_4]. Work by Keith[10], and later by Holm and Josendal[11], showed that carbon dioxide solubility was reduced with increased concentrations of nitrogen and methane. Saxon *et al* [12] found that carbon dioxide solubility decreased as the natural bubble point pressure of crude oil increased, requiring higher carbon dioxide injection pressures. The reduction in solubility due to methane gas was also confirmed by Sayegh and Maini[13] when simulating methane impurities in recycled carbon dioxide gas for the "huff-n-puff" process.

Contrary to the findings Saxon *et al* and Sayegh and Maini, Chung and Burchfield[14] theorized that the solubility of carbon dioxide, in crude oils at reservoir conditions, would gradually increase as more carbon dioxide is injected. They felt that the carbon dioxide will strip the solution gas from the crude causing the methane to be released.

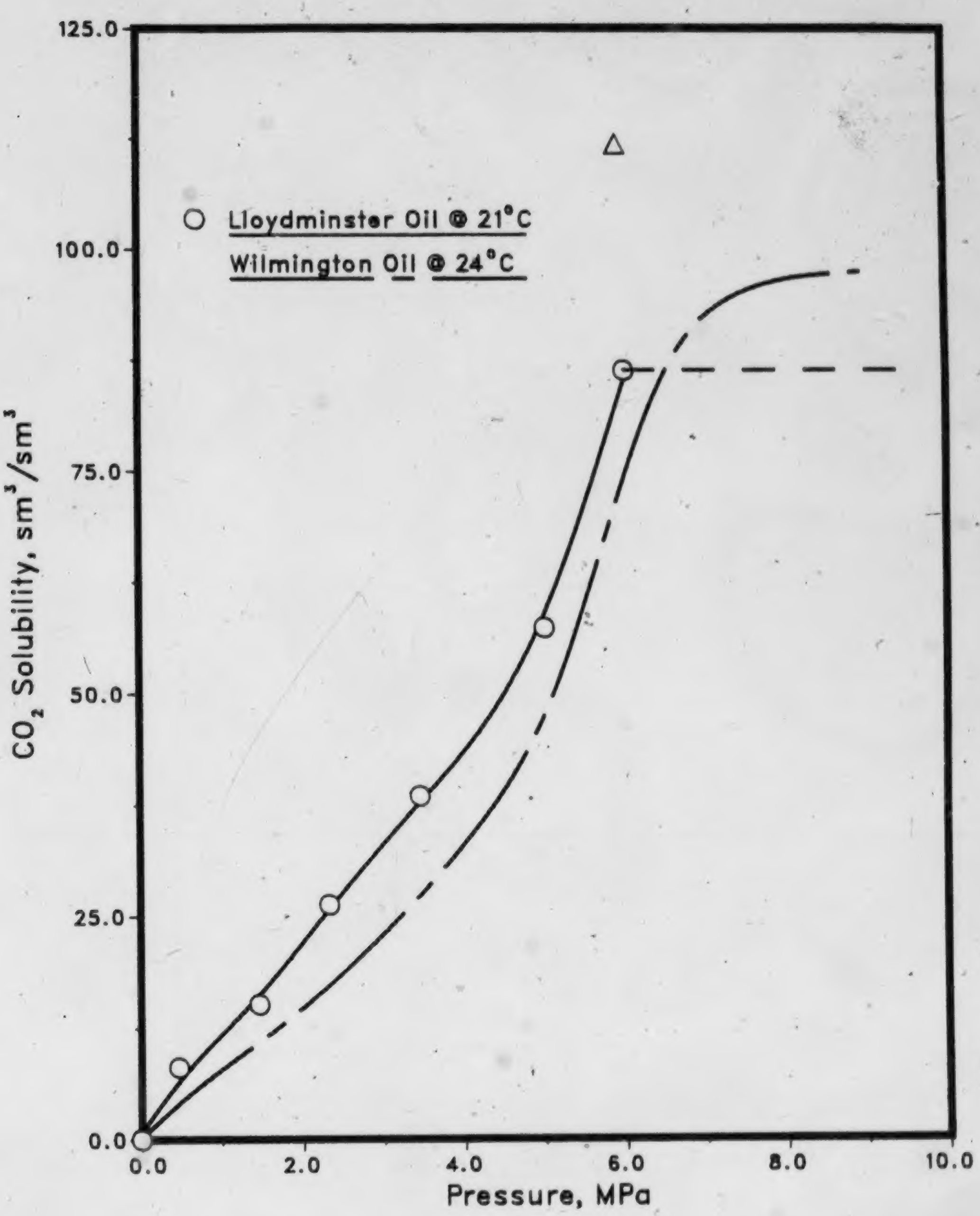


Figure 3.1 – Comparison of Solubility of Carbon Dioxide in Wilmington [17°API] Oil with Lloydminster Aberfeldy [15°API] Oil, After Briggs et al [Ref. 1].

Experimental displacement studies conducted by Zhu[15] in a scaled physical model compared carbon dioxide and nitrogen. Zhu found that oil recovery using nitrogen was similar to that for a waterflood. Oyekan[16] conducted residual oil displacement experiments with nitrous oxide and with carbon dioxide. The results showed that nitrous oxide, a more powerful solvent than carbon dioxide, recovered more residual oil but that its cost rendered the process highly uneconomical.

Several investigators[6,7,14,17] have presented empirical correlations for carbon dioxide solubility in crude oil systems. Mehrotra and Svrcek[18] presented an empirical equation to predict the carbon dioxide solubility in Lloydminster Senlac [14°API] oil.

Their equation is given by:

$$Rs_{(co2)} = C_1 + C_2\, p + C_3\, (p/T) + C_4\, (p/T)^2 \qquad (3.1)$$

where,

$Rs_{(co2)}$ = carbon dioxide solubility [sm^3/sm^3]
p = pressure [MPa]
T = temperature [kelvin]

and,

$C_1 = -68.87$
$C_2 = -8.983$
$C_3 = +1.385 \times 10^4$
$C_4 = -1.976 \times 10^5$

This equation accurately predicts the Briggs and Puttagunta's[7] data for the Lloydminster Aberfeldy oil at pressures above 3.4 MPa. The authors noted that modifications were needed to account for solution gas such as methane.

Carbon dioxide is soluble in water to a much lesser extent than in crude oils. The solubility of carbon dioxide in water is a function of salinity, pressure, and temperature. Data presented by Dodds *et al* [19] show that in the temperature range of 20-70°C and for pressures below 10 MPa, the solubility of carbon dioxide, in fresh water, is less than six percent by weight. Stewart and Munjal[20] conducted carbon dioxide solubility experiments in a synthetic sea water. They found that carbon dioxide solubility was reduced with increasing salinity and temperature. Klins[3] noted that for projects undergoing tertiary recovery, the solubility of carbon dioxide in water must be accounted for.

Diffusion

Carbon dioxide mixes with oil by diffusion as well as by solution. Diffusion is the macroscopic transport of mass, due to random molecular motion, and is independent of any convection within the system.[21,22] Diffusion is not related to the attractive forces as measured by solubility.[2] An increase in temperature enhances diffusion, i.e. increases molecular motion, but reduces solution. Diffusion is a rate process under non-equilibrium conditions while solution, by definition, is the amount of dissolved solvent at equilibrium.

Molecular diffusion is responsible for mass transfer at the pore level, and has been shown to be an important rate controlling mechanism in carbon dioxide floods.[23] Diffusion helps carbon dioxide penetrate into heavy oil which may help to reduce gravitational and viscous instabilities. The volume of carbon dioxide contacting oil may be increased, by diffusion, in cyclic "huff-n-puff" processes by determination of the optimum soak time, viz. accurate knowledge of diffusion coefficients for a particular system.[24]

Several researchers[25,26] have conducted experiments to determine diffusion coefficients of carbon dioxide in hydrocarbons at atmospheric conditions. McManamey and Woolen[26] proposed the following equation, as an inverse function of oil viscosity, for the diffusion coefficients of carbon dioxide in organic liquids :

$$D_o = 1.41 \times 10^{-10} \ \mu_o^{-0.47} \qquad (3.2)$$

where,

D_o = diffusivity coefficient [cm^2/s]
μ_o = dynamic viscosity @ STP [mPa•s]

Denoyelle and Bardon[27] also confirmed that experimental diffusion coefficients were inversely proportional to the oil viscosity.

Research conducted by Denoyelle and Bardon[27], Schmidt *et al* [28], and Rojas and Farouq Ali[29] has shown that the diffusivity of carbon dioxide is as much as five times higher than those of McManamey and Wollen, at elevated pressures for heavy oils and bitumens. The carbon dioxide diffusivity coefficients for Lloydminster Aberfeldy oils[15] are in the range of 2.56×10^{-5} to 3.59×10^{-5} cm^2/s . Rojas and Farouq Ali[29] concluded that while the diffusion of carbon dioxide in heavy oils is high, it represented less than 20 percent of that obtained by solution under the same subcritical conditions.

Literature data[26,27] indicate that the diffusion rate of carbon dioxide in water is greater than the diffusion rate of carbon dioxide in oil. Denoyelle and Bardon[30] found that the diffusion of carbon dioxide in a liquid (oil and water) proceeded at an intermediate rate between that in water alone or in oil alone. They also pointed out that the porous medium has a negligible effect on molecular diffusion due to the pore scale being so much larger than the molecular scale.

Dispersion

Additional mixing of fluid occurs in the porous medium due to velocity. This additional mixing is due to the dispersive force of attraction which occurs in highly polarizable molecules such as hydrocarbons[31]. For the moderate velocities encountered at reservoir conditions however, transport of carbon dioxide by convective dispersion is largely surpassed by molecular diffusion[2].

Effects of Carbon Dioxide on Oil, Water, and Formation Properties

Dramatic changes may occur to the formation fluids and rock when exposed to carbon dioxide. The most notable of these changes is the reduction in oil viscosity. This section describes in detail what happens in the reservoir when carbon dioxide is injected into the formation.

Properties of Pure Carbon Dioxide

In Saskatchewan reservoirs carbon dioxide normally exists as a gas and possibly as a liquid. Some physical properties of pure carbon dioxide are as follows:

critical pressure: $p_c = 7.40$ MPa
critical temperature: $T_c = 31.0$°C
critical volume: $V_c = 0.0022\ m^3/kg$
molecular weight: MW = 44.01 g/g-mol
specific gravity to air: Sg = 1.5194 (air = 1.0 at STP)
normal boiling point: nBP = -78.5°C (at 1 atm. pressure)

Carbon dioxide is a relatively dense gas, approximately fifty percent heavier than air at atmospheric conditions. In this investigation, the Starling equation of state[32] was used in calculating the molar density of pure carbon dioxide gas. According to Starling[32], his equation predicts experimental density data with an average uncertainty of 1%. This equation has the following general form.

$$p = \rho RT + (B_oRT - A_o - C_o/T^2 + D_o/T^3 - E_o/T^4)\rho^2 + (bRT - a - d/T)\rho^3 + \beta(a + d/T)\rho^6 + (c\rho^3/T^2)(1 + \gamma\rho^2) \quad (3.3)$$

where,

p = pressure [MPa]
T = temperature [kelvin]
ρ = molar density [kg-mol/m^3]

and,

$A_o = 0.176976$
$B_o = 0.024588$
$C_o = 2.451876 \times 10^4$
$D_o = 1.883482 \times 10^6$
$E_o = 2.631556 \times 10^4$

$\beta = 0.0000961229$
$\gamma = 0.006421$

$a = 0.009434$
$b = 0.003781$
$c = 1.4197888 \times 10^3$
$d = 0.055761$

$R = 0.008314$

Figure 3.2 shows the molar density of carbon dioxide gas increasing with pressure at a constant temperature of 20.6°C. The density of pure carbon dioxide gas at 1.0 MPa and 20.6°C is approximately 0.019 g/cm^3

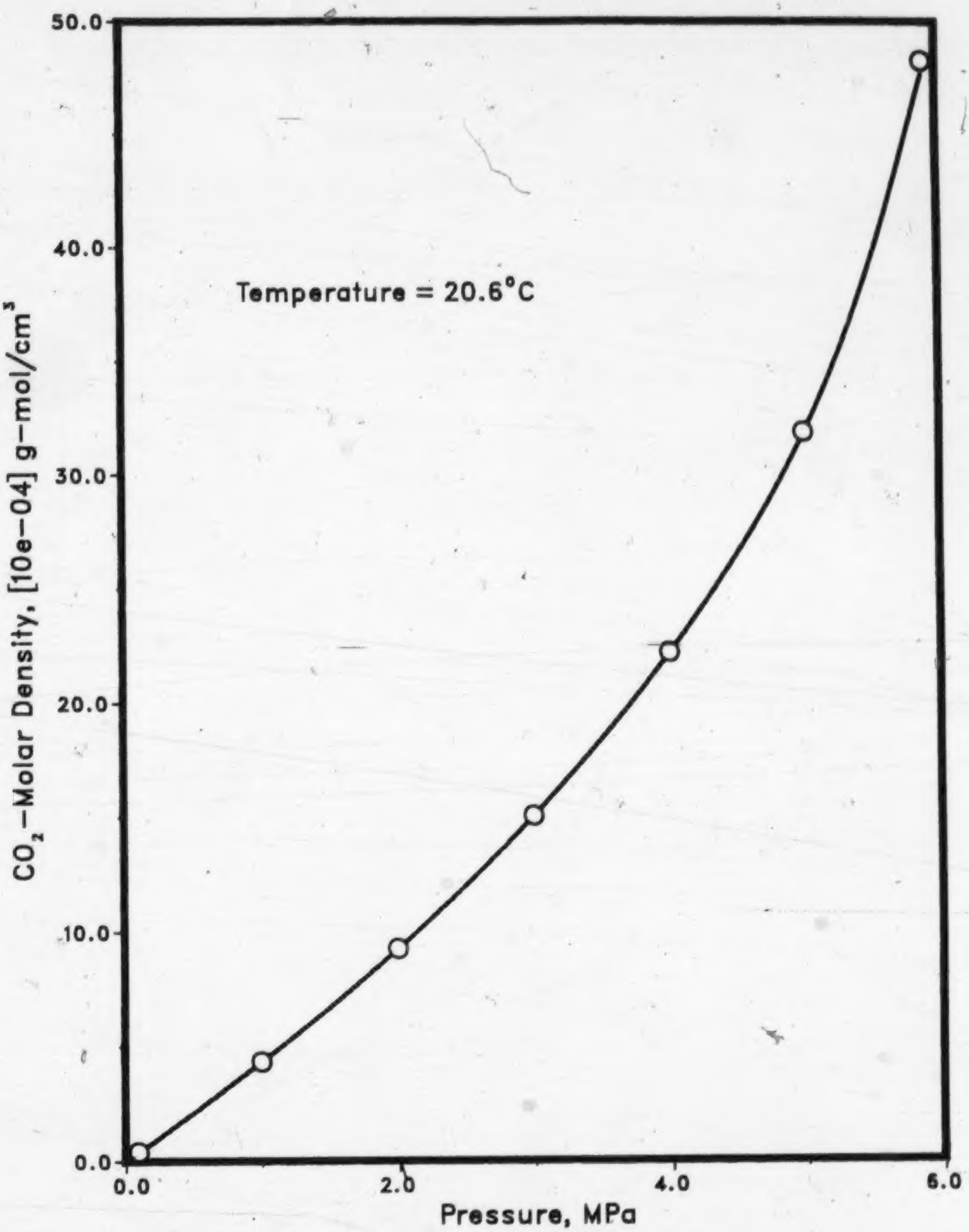
The viscosity of carbon dioxide gas is a strong function of pressure and temperature. Goodrich[33] presented data for the viscosity of pure carbon dioxide at various pressures and temperatures. Goodrich found that carbon dioxide gas viscosity increased considerably with pressure and decreased to a lesser extent with temperature. Experiments conducted at atmospheric conditions by Carr *et al* [34] show that carbon dioxide gas is more viscous than methane, ethane, propane, and hydrogen sulphide but less viscous than air and nitrogen at any given temperature. The viscosity of pure carbon dioxide gas at 1.0 MPa and 20.6°C is approximately 0.022 mPa•s.

Viscosity Reduction

The most important effect of carbon dioxide on crude oil systems is the large reduction of oil viscosity. Five to thirty fold reductions in viscosity at carbon dioxide saturation pressures have been reported. The viscosity of oil saturated with carbon dioxide is a function of temperature, pressure, and concentration of dissolved carbon dioxide.

A number of researchers[2,35-38] have found that greater percentage reductions in viscosity occur at lower operating temperatures. Killesreiter[38] noted that above 145°C, the effect of dissolved carbon dioxide on oil viscosity was negligible. Experiments conducted by Jacobs *et al* [36] on Athabasca bitumen showed that the most dramatic decreases in viscosity, due to carbonation, occurred at temperatures below 100°C. This is due to the increased carbon dioxide solubility at lower temperatures.

Work by Rojas and Farouq Ali[2], and others[6,39,40] indicated that the higher the initial oil viscosity, the greater the percentage



Note : Data points generated from the Starling Equation–Of–State, [Ref. 32].

Figure 3.2 – Carbon Dioxide Molar Density Vs. Pressure.

reduction in viscosity when saturated with subcritical carbon dioxide. Rojas and Farouq Ali[2] reported a 95.6 percentile decrease in viscosity for a 1080 mPa•s oil and a 98.3 percentile decrease in viscosity for a 4900 mPa•s oil, both saturated with subcritical carbon dioxide at 5.5 MPa and 21°C. They also noted that these reductions in viscosity, by carbon dioxide saturation, were similar to heating the oil samples to approximately 90°C.

Figure 3.3 (After Ref. 7) illustrates the effect of carbon dioxide on the viscosity of Lloydminster Aberfeldy oil at 20.6°C. Briggs *et al* [4] presented the following equation to represent this data.

$$\ln \mu_o = (8.50313 + 0.042127\ p) - 0.081226\ X_{CO_2} \qquad (3.4)$$

where,

μ_o = oil viscosity [mPa•s]
p = carbonation pressure [MPa]
X_{CO_2} = mole percent CO_2, assuming oil MW=400 g/g-mol

Equation (3.4) assumes saturation pressure is less than 6 MPa, and the temperature is constant at 20.6°C. "The mean deviation between the experimental viscosity values and values calculated from the above equation is ± 4.02%."[4] For heavy oils, a large percentage of the total viscosity reduction by carbonation is obtained at low pressures [<2 MPa] and low temperatures [<100°C][15].

Another factor which influences heavy oil-carbon dioxide viscosity, is the equilibrium time, after which there is no change in viscosity with time. Experiments conducted by Goss and Exall[41] showed that a 18000 mPa•s sample of bitumen, exposed to a 6.8 MPa carbon dioxide pressure at 50°C, required 12.5 days to reach equilibrium. The final viscosity was 8000 mPa•s, a 55.6 percentile decrease.

Scott[43] analyzed laboratory data of Lloydminster crude oil published by the Petroleum Recovery Institute[44]. He noted that as the carbonation pressure was decreased and carbon dioxide liberation occurred, the viscosity reduction was retained even at relatively low

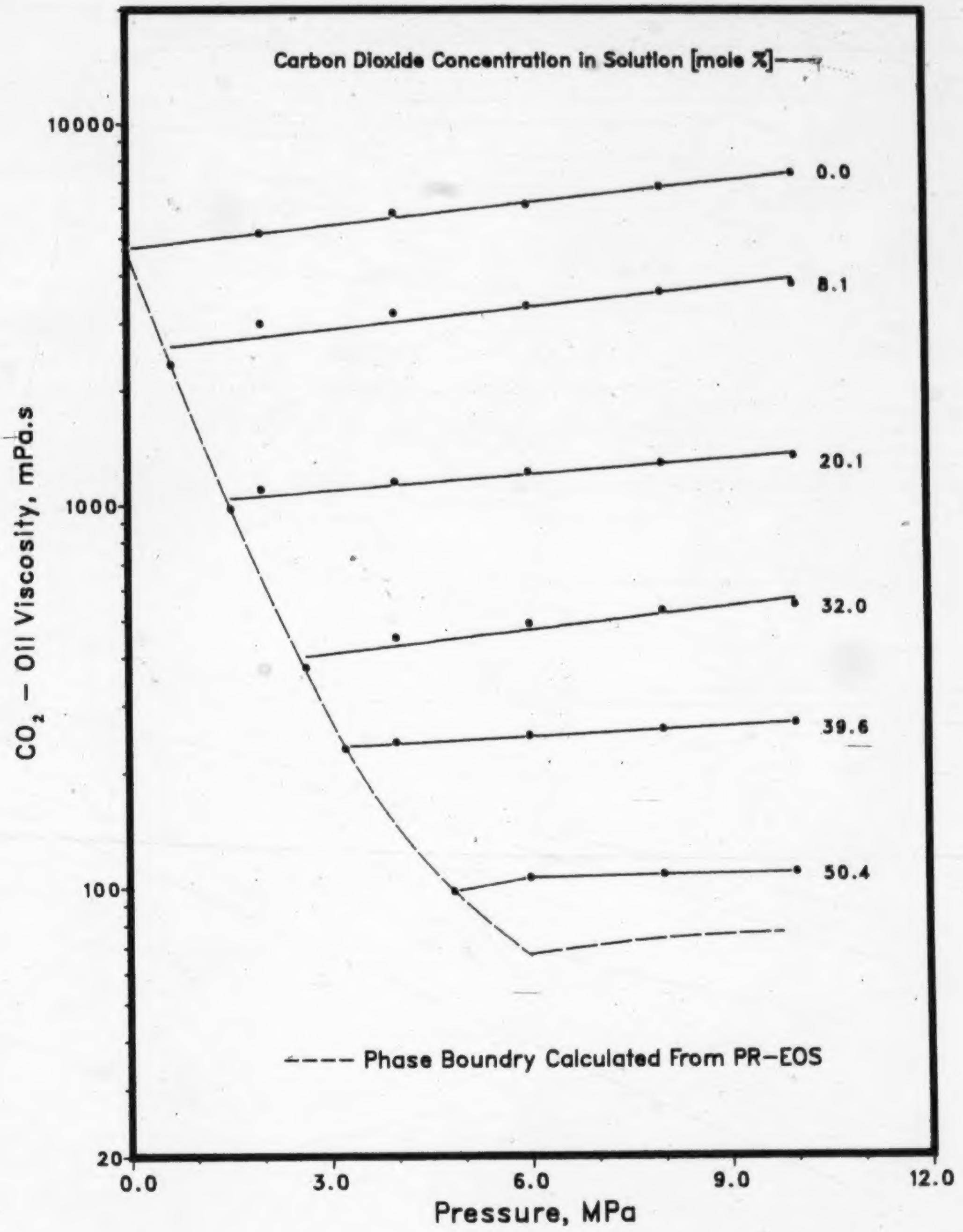


Figure 3.3 – The Effect of Carbon Dioxide on the Viscosity of Lloydminster Aberfeldy [15°API] Oil at 20.6°C, After Briggs et al [Ref. 7].

pressures. He concluded that the viscosity reduction at reservoir conditions could be maintained for an extended period of time after the injected carbon dioxide had been produced.

Flock and Boogmans[42] stated that the effect of carbonation has been shown to have a minimum effect on the viscosity of water. Due to the relatively low solubility, the viscosity of formation water is assumed to be independent of carbon dioxide saturation. Tumasyan *et al* [45] found that the viscosity of water slightly increased when fully saturated with carbon dioxide. They found that the viscosity of formation water increased from 0.562 to 0.650 mPa•s when saturated with carbon dioxide at 6.9 MPa and 52°C, an increase of 15.6%.

Fluid Expansion

Crude oils swell when contacted with carbon dioxide. The amount of swelling increases with increased carbon dioxide solubility. Briggs and Puttagunta[7] presented swelling factors for Lloydminster Aberfeldy Crude oil in the presence of carbon dioxide at 20.6°C (see Figure 3.4, After Ref. 7). Their swelling factor is defined as:

$$\text{S.F.} = \frac{\text{Volume of Oil Containing } X_{CO_2} \text{ @ p \& 20.6°C}}{\text{Volume of Oil Containing No } CO_2 \text{ @ 4 MPa \& 20.6°C}} \qquad (3.5)$$

As can be seen from Figure 3.4, the swelling factors increase dramatically at pressures below the carbon dioxide bubble point pressure. The rapid increase in swelling factor, with increasing carbon dioxide injection, at approximately 6 MPa is due to the formation of a liquid layer of carbon dioxide floating on top of the oil. Miller and Jones[6] also showed that oil expansion increases with carbonation pressure and subsides with rising temperatures.

Holm and Josendal[11] indicated that there is some expansion of water [2-7%] when carbon dioxide goes into solution. Mungan[37] suggested that because the carbon dioxide solubility was much lower in water relative to oil, the water expansion would be less than 1 percent and therefore the change would be insignificant and may be ignored.

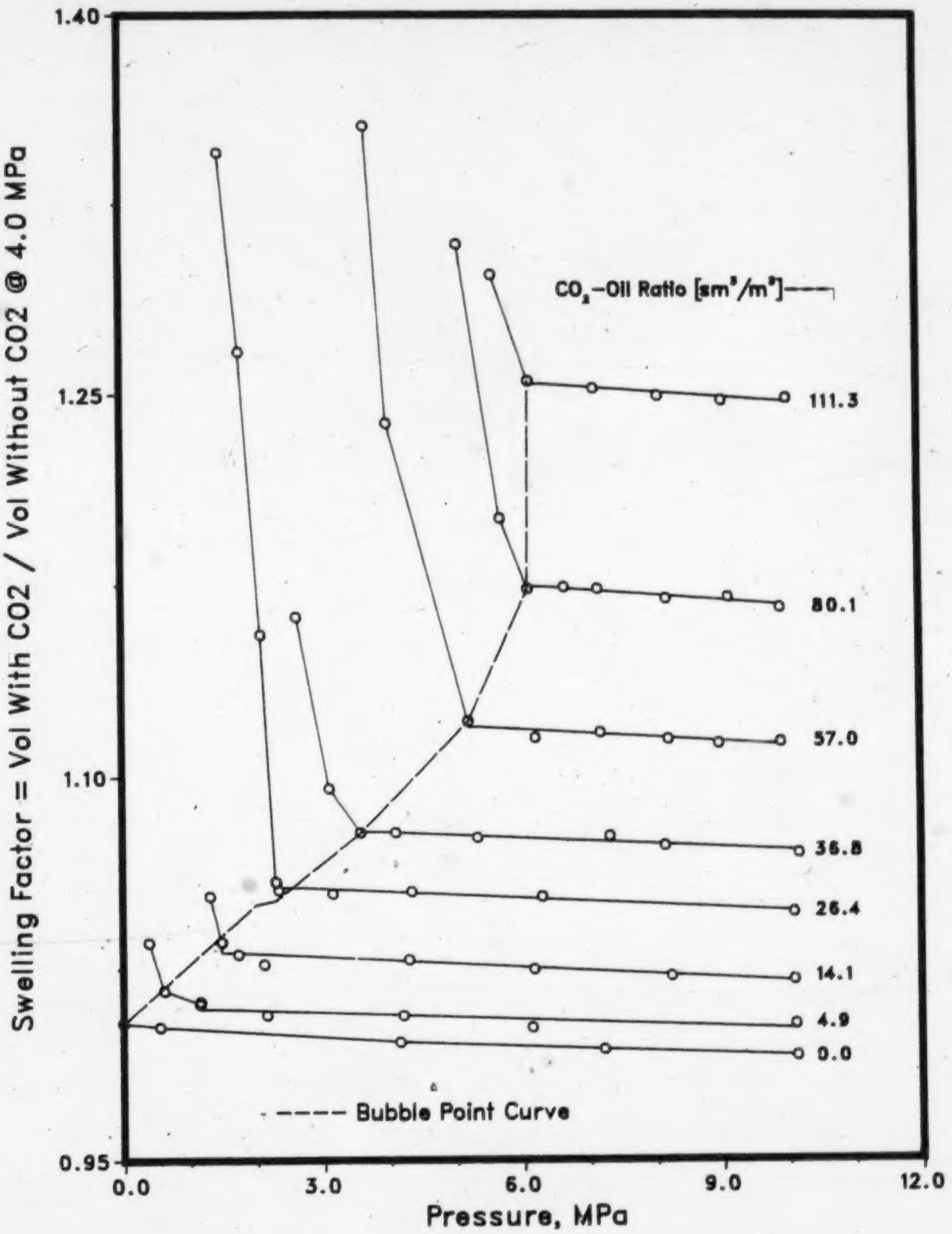


Figure 3.4 – Swelling Factors of Lloydminster Aberfeldy [15°API] Oil at 20.6°C, After Briggs et al [Ref. 7].

Figure 3.5 is a composite plot of swelling factors, solubility, and viscosity of carbon dioxide in Lloydminster Aberfeldy oil at 20.6°C. All of the data for this plot was taken from Reference 7.

Density Change

Holm and Josendal[11] also noted that carbon dioxide has a surprising effect on the density of crude oil. Opposite to what one may expect, the density of crude oil increases as it becomes saturated with carbon dioxide. Miller and Jones[6] also found that Wilmington [17°API] oil density increases with increasing carbonation pressure, illustrated in Figure 3.6 (After Ref. 6). Quail *et al* [18] presented the following equation for the density of Lloydminster Senlac [14°API] oil.

$$\rho_o = (C_1 - C_2) \frac{\exp(-C_3 [CO_2])}{(1 + C_4 [CH_4])} \tag{3.6}$$

where,

ρ_o = oil density [g/cm^3]
$[CO_2]$ = concentration of dissolved CO_2 [mole %]
$[CH_4]$ = concentration of dissolved CH_4 [mole %]

and,

$C_1 = 1.1685$
$C_2 = 0.6848 \times 10^{-3}$
$C_3 = 0.1495 \times 10^{-3}$
$C_4 = 0.1279 \times 10^{-3}$

The authors noted that pressure had a negligible effect on the density but that increasing dissolved gas concentrations caused a significant reduction in oil density and were therefore accounted for.

Parkinson and de Nevers[46] presented limited data on water density measurements of carbon dioxide saturated solutions at pressures up to 3.4 MPa. Analysis of this data shows that the density of carbon dioxide-water systems, in equilibrium, is a weak linear function of pressure at constant temperature. Holm and Josendal[11] also indicated that carbon dioxide has a small effect on the density of water.

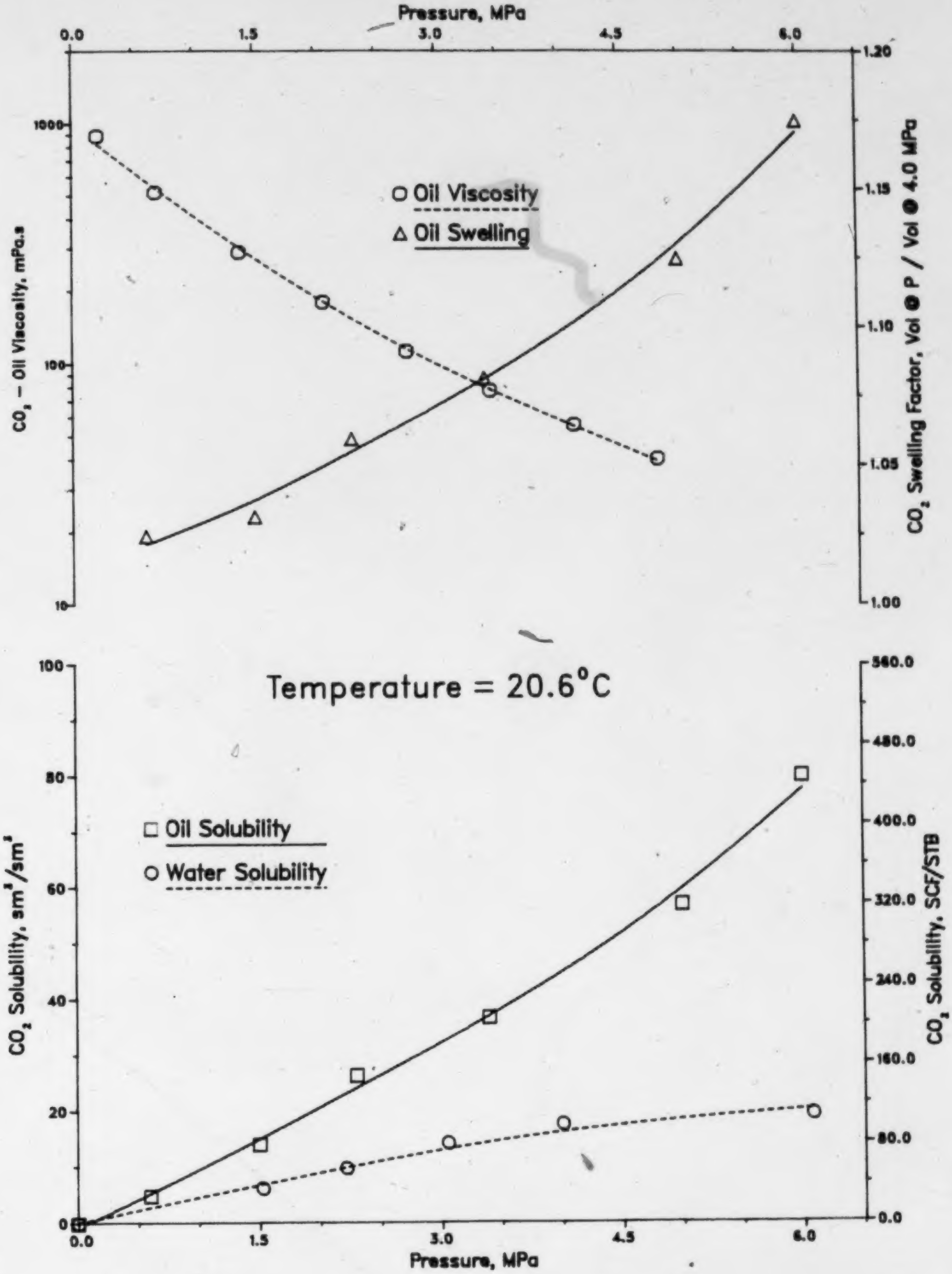


Figure 3.5 – Swelling Factors, Solubility and Viscosity of Carbon Dioxide in Aberfeldy Oil [Ref. 7].

Interfacial Tension Reduction

Beecher and Parkhurst[9] conducted experiments in 1929 to determine the interfacial tension between crude oils and gases. Their results indicated a reduction of approximately 20% in the surface tension of crude oils. Breston and Macfarlane[47] showed that the interfacial tension between Bradford crude and water can be reduced from 28.8 to 18.1 mN/m by carbonation at 5.2 MPa. Interfacial tension investigations by Scott *et al* [48] and Farouq Ali *et al* [49], showed that any change in pH from neutral [pH=7], decreased the interfacial tension.

Rojas and Farouq Ali[2] found that interfacial tension decreases moderately with increasing carbonation pressure of brine. The interfacial tension was reduced from approximately 25 to 16 mN/m when the pressure was increased from 0.1 to 5.5 MPa (see Figure 3.7). They indicated that the reduction in interfacial tension may be due to the action of carbonic acid on the nitrogen bases, found in Lloydminster Aberfeldy crude oil. The formation of surfactants would then concentrate at the oil-water interface. Martin[50] postulated that the carbon dioxide chemically bonds with these nitrogen bases to form polar compounds, which would drastically reduce the interfacial tension of oil-water systems.

The reduction in interfacial tension, due to concentrated surfactants at the oil-water interface, may promote the in-situ formation of water-in-oil emulsions. Rojas and Farouq Ali[2] describe the mechanisms of in situ emulsification, during immiscible displacement of heavy oil by carbon dioxide, as follows:

1. Fingers of formation water in the swollen carbonated oil lead to the formation of large brine droplets inside the oil.
2. The reduction in interfacial tension between the oil and the acidic brine breaks down the droplets into small, more stable brine droplets.

Rojas[22] observed the production of viscous gasified emulsions after brine breakthrough in scaled model displacement experiments.

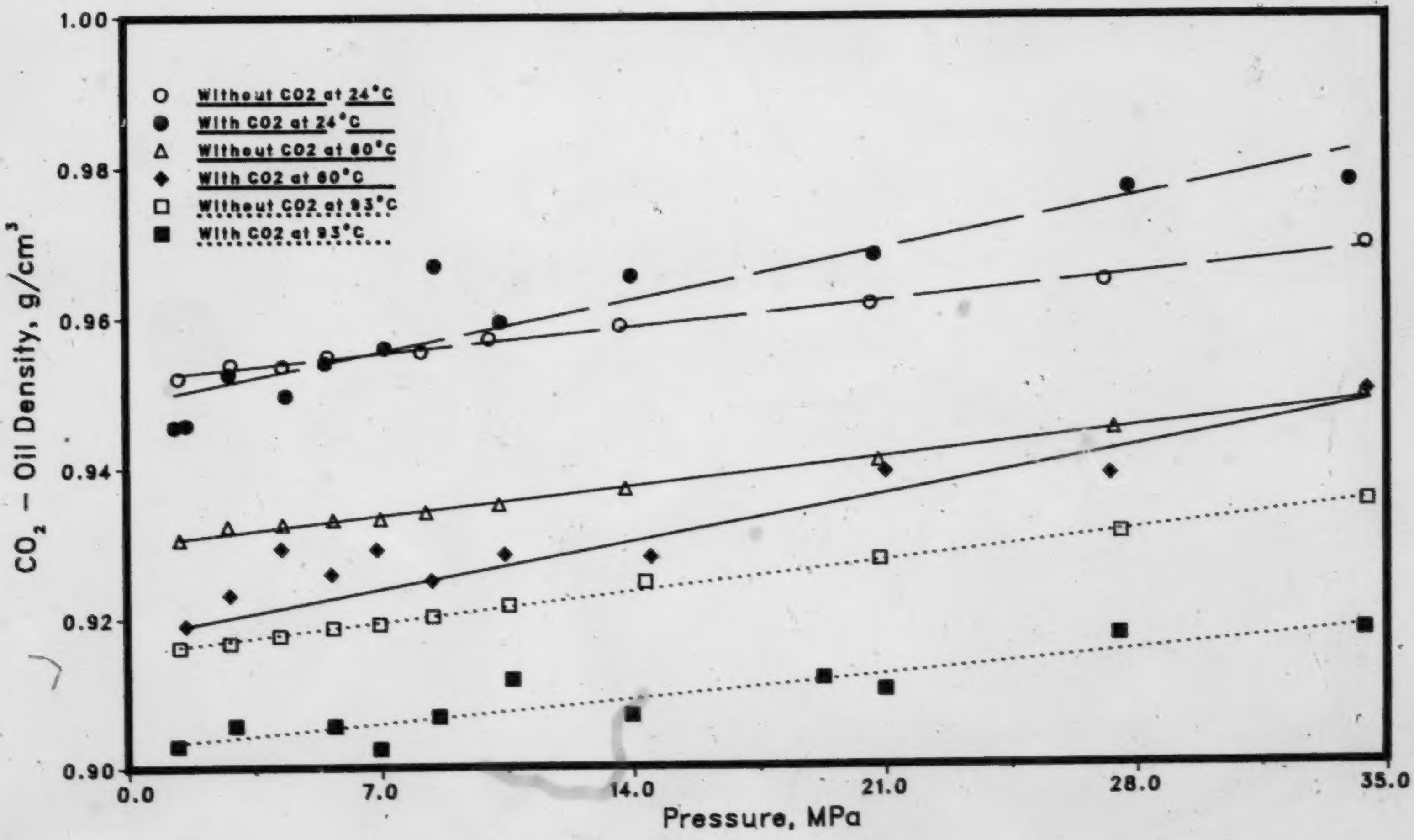


Figure 3.6 – Effect of Pressure on the Density of Wilmington [17°API] Oil @ 24, 60, and 93°C, After Miller and Jones [Ref. 6].

Asphaltene Flocculation

Multiple liquid phases may exist in equilibrium when carbon dioxide and crude oil mix. In some cases a solid phase may appear. Deposition of asphaltene precipitates can cause serious problems in the reservoir, such as constriction of fluid flow passages or injectivity problems associated with wettability reversal[51]. Hirschberg *et al* [52] define asphaltenes as 'the n-heptane insoluble fractions of crude obtained following the Institute of Petroleum Method Test 173'. Asphaltene precipitation occurs when the hydrocarbons and polar fractions lose their ability to disperse colloidally the asphaltene fraction[53].

Factors which influence asphaltene flocculation are: crude oil composition, pressure, temperature, and properties of asphaltenes. Klins[3] noted that the dominant factor was the initial proportion of asphaltene base ends in crude oils. Several investigators[1,52-54] have conducted asphaltene flocculation experiments with light oils, concluding that the extent of carbon dioxide-induced asphaltene precipitation correlates with pressure and temperature as they relate to the development of miscibility. Observations by Monger and Fu[54] suggest that the ability of carbon dioxide to extract and dissolve hydrocarbons contributes to the mechanisms responsible for carbon dioxide-induced organic deposition. Bryant and Monger's[55] phase behavior measurements have shown that extensive asphaltene precipitation is associated with the development of multi-contact miscibility. An important note to the findings of Hirschberg *et al* [52] is that asphaltene flocculation appears to be reversible when pressures are reduced.

Fuhr *et al* [56] studied the effects of carbon dioxide on asphaltene flocculation in a Lloydminster heavy oil. Experiments showed that an increase in carbon dioxide pressure increased the tendency for asphaltenes to flocculate from toluene solutions in heavy oil. Further studies showed that the onset of asphaltene flocculation occurred at higher pressures as the toluene-to-oil ratio decreased. It was also noted that asphaltene precipitation decreased as temperatures were

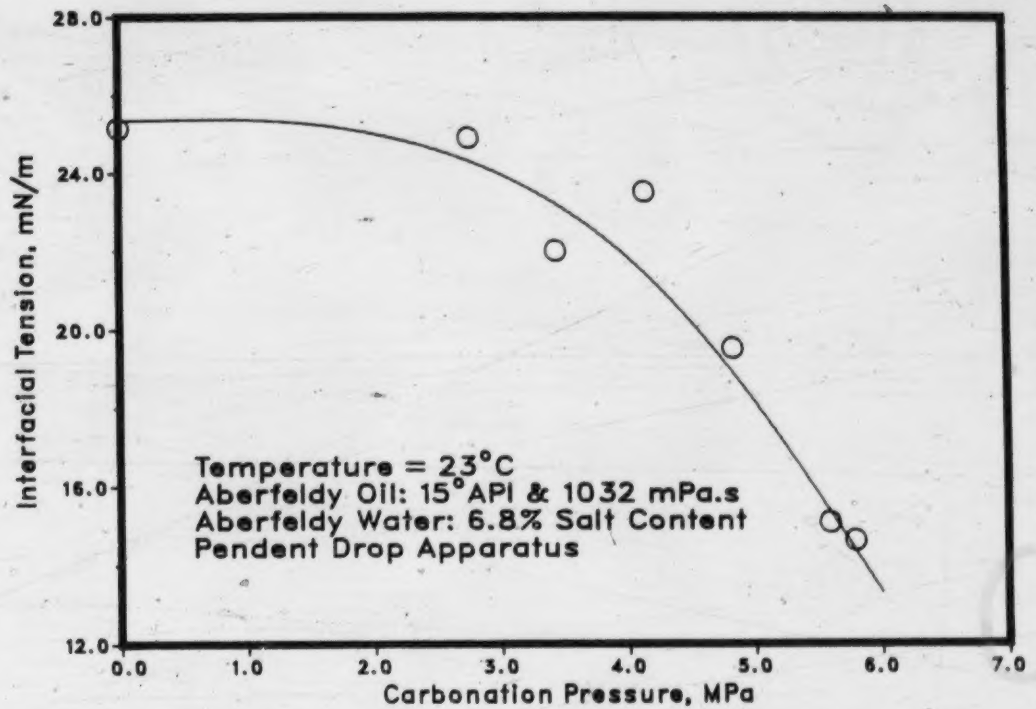


Figure 3.7 – Effect of Carbon Dioxide on the Interfacial Tension Between Aberfeldy Oil and Formation Water.

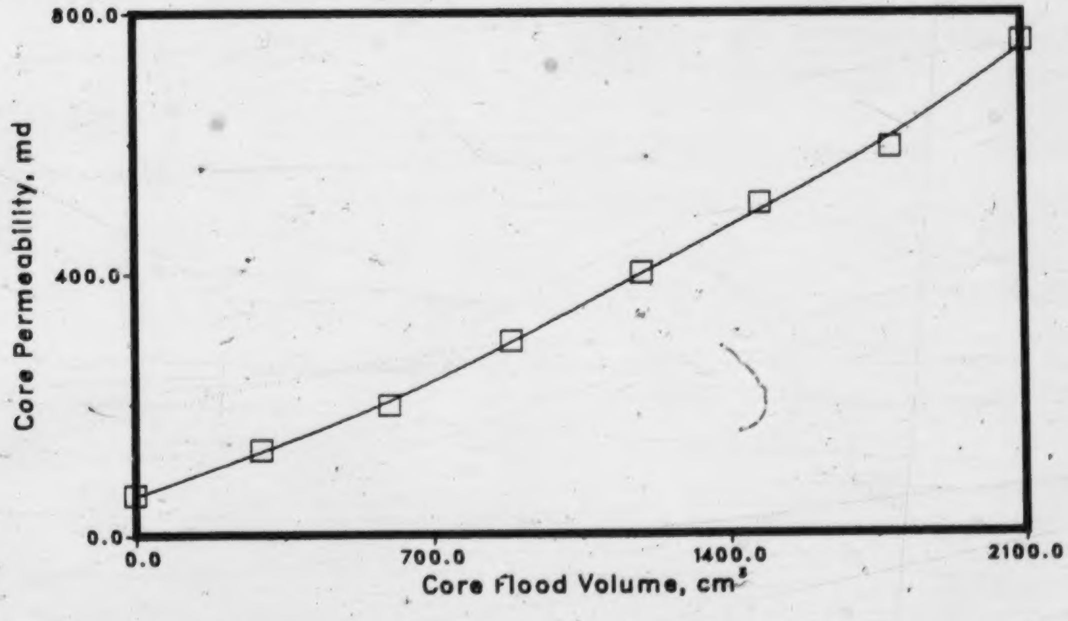


Figure 3.8 – Permeability Profile for a Jurassic Sandstone Under a 6.9 MPa Carbonated Waterflood, After Ross et al [Ref. 57].

raised, viz. carbon dioxide solubility decreased. For the Lloydminster heavy oil sample, asphaltenes began to precipitate at carbonation pressures greater than about 3.5 MPa without the addition of heptane.

Permeability Changes

Many formations contain carbonates in some form. Carbonates constitute the bulk matrix in limestone and dolomite reservoirs. In sandstone reservoirs, carbonates are often found as cements consolidating the sand grains. The carbonates most commonly found in reservoir rocks are those of calcium and magnesium[57].

Carbonated water, formed when injecting carbon dioxide and water into a well, will react with the carbonate minerals in the reservoir. Ellis[58] summarized the chemical process as follows:

1. Carbon dioxide and water are injected into the reservoir and the carbon dioxide dissolves in the water forming hydrogen carbonate, which then dissociates to give carbonic acid.

$$CO_{2_g} \Leftrightarrow CO_{2_{aq}} + H_2O \Leftrightarrow H_2CO_{3_{aq}} \Leftrightarrow H^+_{aq} + HCO_3^-{}_{aq} \qquad (3.7)$$

2. The acid then reacts with the carbonate, such as calcite

$$H^+_{aq} + HCO_3^- + CaCO_{3_s} \Leftrightarrow Ca^{2+}_{aq} + 2(HCO_3^-)_{aq} \qquad (3.8)$$

The factors that affect the equilibrium of the above equations are: changes in the concentrations of reactants and products, pressure, and temperature.

Lund and Fogler[59] suggested that the dissolution occurred at preferred sites such as exposed grains and constrictions. On the contrary, Ross *et al* [57] felt that the phenomenon of channeling is more likely to be the dominating mechanism leading to increased permeability. Figure 3.8 (After Ref. 57) shows that a North Sea Jurassic sandstone core [80% quartz. and 20% ferroan calcite] increased in permeability from 60 to 770 md when flooded with carbonated water at 6.9 MPa and 20°C. They also noted that porosity was not significantly altered. Klins[2] suggested that carbonic acid may also stabilize clays, reducing swelling and plugging, due to the reduction in pH.

Several investigators[2,60,61] have also noted the negative effects of rock dissolution. They found that small particles and/or carbonate precipitates could block pore channels, thus reducing permeability.

Factors Determining Recovery Efficiency

The overall efficiency of any recovery method may be broken down into a combination of individual process efficiencies. The equation of overall recovery efficiency is as follows.

$$E_R = E_A \bullet E_V \bullet E_D \bullet E_M \qquad (3.9)$$

where,

E_R = overall recovery efficiency
E_A = areal sweep efficiency
E_V = vertical sweep efficiency
E_D = displacement efficiency
E_M = mobilization efficiency

Various enhanced oil recovery techniques aim to improve any one or more of the above efficiencies. Herbeck *et al* [62] suggested that the primary effect of immiscible carbon dioxide flooding is to improve the displacement efficiency, and that a secondary effect is to improve the mobilization efficiency.

Displacement Efficiency

Displacement efficiency is defined as the fraction of mobile oil in the swept zone that has been displaced. Displacement efficiency is a function of the volume of fluids injected, fluid viscosities, and the relative permeabilities. By definition, displacement efficiency is the displacement in the swept zone only, and is therefore constant until breakthrough, viz. increases in recovery prior to breakthrough are due to increasing volumetric sweep [$E_A \bullet E_V$].

The following equation, as a function of fluid injected, is used to quantify the displacement efficiency.

$$E_D\,(\,PV_i\,) = \frac{S_{oi} - \overline{S_o}}{S_{oi} - S_{orp}} \qquad (3.10)$$

where,

S_{oi} = initial oil saturation
$\overline{S_o} = 1 - \overline{S_w}$ = average oil saturation in the swept zone
S_{orp} = ultimate residual oil to a given process
PV_i = pore volumes of fluid injected

As can be seen from equation (3.10), improved displacement efficiency results from a decrease in $\overline{S_o}$ and/or an increase in S_{orp}.

Viscous Instabilities

The primary purpose of the immiscible carbon dioxide flooding process is to decrease the effective viscosity of the displaced fluid relative to the displacing fluid. The viscosity of carbon dioxide at 1.0 MPa and 20.6°C is approximately 0.022 mPa•s. The viscosity of oil in the Lloydminster area varies from 100 to 5000 mPa•s, while the viscosity of formation water is approximately 1.1 mPa•s.

The immiscible carbon dioxide process may be visualized as oil viscosity reduction, due to carbon dioxide, followed by water immiscibly displacing the reduced viscosity oil. Considering the above, and assuming both oil and water are incompressible, the Buckley-Leverett[63] fractional flow analysis may be used to relate the viscosity ratio to $\overline{S_w}$. This relationship is shown schematically in Figure 3.9. The shaded portion represents a band of fractional flow curves which may exist depending on the amount of carbon dioxide saturation. The lower boundary (left curve) represents the immiscible displacement of oil, without any carbon dioxide, by water. The upper boundary represents the immiscible displacement of an oil, fully saturated with carbon dioxide, by water. As more carbon dioxide contacts the oil, the viscosity ratio between oil and water decreases and the fractional flow curve shifts to the right. The average water saturation behind the front increases thus enhancing the displacement efficiency, particularly after breakthrough.

Spivak and Chima[64] conducted simulation experiments to determine the mechanisms of immiscible carbon injection in the Wilmington field of California. They found that oil recovery at breakthrough, determined from Buckley-Leverett[63] analysis, significantly increased as the oil-water viscosity ratio was reduced (see Figure 3.10).

Mobility Ratio

Mobility Ratio is defined as the ratio of displacing phase mobility to the displaced phase mobility[65]. The mobility ratio equation for the displacement of oil is as follows.

$$M = \frac{\left(k_{rd} / \mu_d \right)_{\text{displacing}}}{\left(k_{ro} / \mu_o \right)_{\text{displaced}}} \qquad (3.11)$$

where,

k_r = relative permeability at average phase front
μ = fluid viscosity

The adverse mobility ratio, due to the large viscosity differences, encountered in heavy oil-carbon dioxide systems may result in the formation of viscous fingers. Viscous fingering causes early carbon dioxide breakthrough and drastic reductions in the displacement efficiency. The mobility ratio for heavy oil-carbon dioxide systems is greatly lowered due to the large reductions in oil viscosity (see Figure 3.3).

In 1958, Caudle and Dyes[66] proposed injecting water with solvent to reduce solvent [displacing phase] mobility. The injection of water reduces the displacing phase mobility, by decreasing the relative permeability of the reservoir rock to the displacing phase. For the immiscible carbon dioxide process, the injection of water reduces the relative permeability to carbon dioxide thus decreasing the rapid

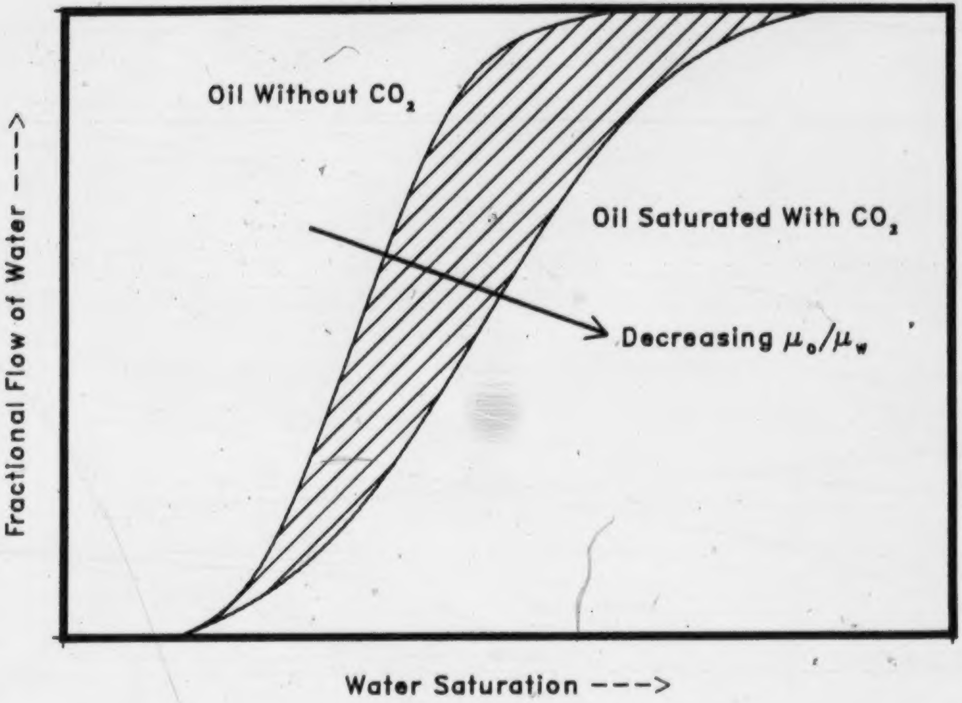


Figure 3.9 – Schematic Fractional Flow Curves for Immiscible Carbon Dioxide Flooding.

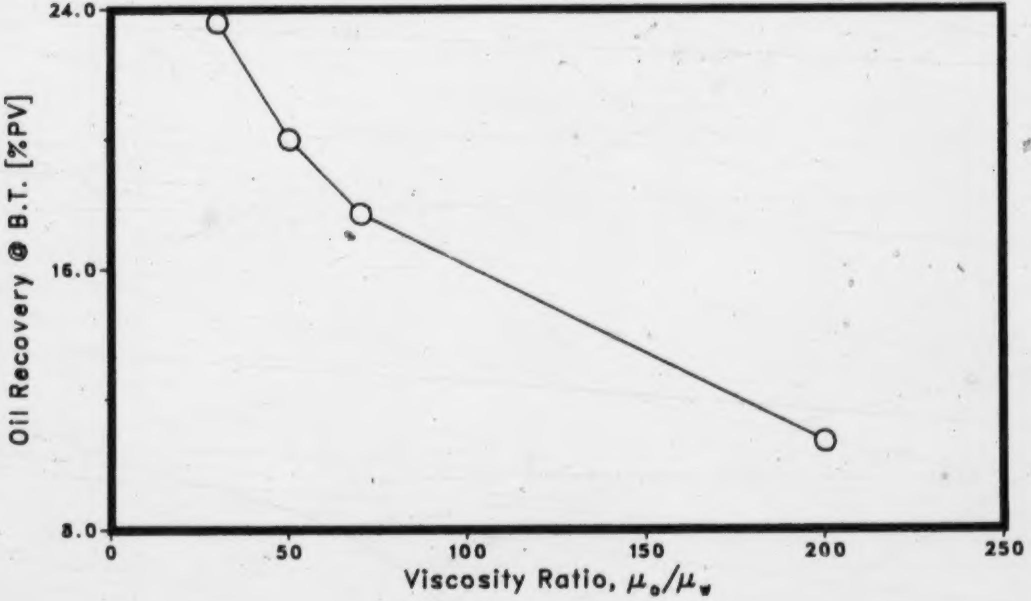


Figure 3.10 – Effect of Viscosity Ratio on Oil Recovery at Breakthrough, After Spivak and Chima [Ref. 64].

production of the gas phase. Various carbon dioxide-water injection strategies, and their effects on mobility control, are discussed in a later section.

Bernard *et al* [67] pointed out that injecting water, as a mobility control agent for carbon dioxide floods, may have several negative effects including trapping of oil, increased water flow, and decreased extraction of hydrocarbons from oil by carbon dioxide. Several investigators[64,67-69] have studied the effectiveness of foaming surfactants for carbon dioxide mobility control. Di Julio and Emanuel[68] conducted carbon dioxide-foam displacement experiments on a 14°API California heavy oil. Their results indicated the ability of small amounts of foam to reduce carbon dioxide mobility, and increase recovery over a water-alternating-carbon dioxide flood. The major problem associated with foams is that the foams tend to breakdown, losing their mobility control mechanism, within a relatively short period of time.

In-Situ Emulsion Formation

Rojas and Farouq Ali[2] suggested that the reduction in interfacial tension between the displacing phase and oil leads to the formation of a water-in-oil emulsion. Rheological studies conducted by Farouq Ali *et al* [70] on carbon dioxide-Aberfeldy water emulsions have shown that emulsion viscosity, at atmospheric conditions, is of the order of 7000 mPa•s. These studies indicate that the emulsion forms in thin banks thus improving the mobility ratio without appreciably increasing pressure drop.

Blowdown Recovery

Blowdown recovery is the oil recovered upon the termination of a flood by depleting the pressure in the reservoir to a low value. The recovery mechanism is analogous to a solution gas drive. The fluids contain drive energy due to dissolved carbon dioxide under pressure. As the pressure is reduced, the carbon dioxide in solution expands and drives the fluids from the reservoir. Blowdown recovery decreases the residual oil saturation [S_{orp}], thus increasing the displacement efficiency. Rojas and Farouq Ali[2] reported a strong correlation between blowdown recovery and the volume of carbon dioxide retained at the start of the blowdown recovery phase in scaled physical model studies.

Mobilization Efficiency

Klins[3] defines mobilization efficiency as, "the fraction of oil in place that ultimately could be displaced by a given process", i.e. the ultimate displacement efficiency. Mobilization efficiency is independent of the volume of fluid injected and is governed primarily by the ratio of capillary to viscous forces and interphase mass transfer[3]. The following equation is used to quantify the mobilization efficiency.

$$E_M = \frac{S_{oi} / B_{oi} - S_{orp} / B_{of}}{S_{oi} / B_{oi}} \qquad (3.12)$$

where,

S_{oi} = initial oil saturation
B_{oi} = initial oil formation volume factor
S_{orp} = residual oil to a given process
B_{of} = final oil formation volume factor

As can be seen from Equation (3.12), improved mobilization efficiency results from a decrease in S_{orp} and/or an increase in B_{of}. Blowdown recovery increases mobilization efficiency by reducing the residual oil saturation, as described earlier.

Capillary Number Effects

The capillary number is used to characterize the ratio of capillary to viscous forces. The equation for the capillary number is as follows.

$$N_c = \frac{\upsilon \mu}{\sigma} = \frac{k\left(\frac{\Delta p}{\Delta L}\right)}{\sigma} \qquad (3.13)$$

where,

N_c = capillary number	[dimensionless]
υ = displacing fluid Darcy velocity	[m/s]
μ = displacing fluid viscosity	[Pa•s]
σ = interfacial tension	[N/m]
k = absolute permeability	[m^2]

Several investigators[2,71-73] have shown the relationship between residual oil saturation and capillary number. Figure 3.11 (After Ref. 3) is a compilation of several investigations on the recovery of residual oil versus capillary number. The most important point to note is the significant increase in capillary number [3 to 4 orders of magnitude] required to reduce the residual oil saturation below that for a conventional waterflood.

The immiscible carbon dioxide flooding process increases the capillary number by reducing the interfacial tension [IFT] between the displacing and displaced phases (see Figure 3.7). As well, permeability may increase due to dissolution of carbonates. The aforesaid factors would increase the capillary number by less than one order of magnitude. Excessively high pressures would be required to increase the pressure gradient [$\Delta p/\Delta L$] and reduce the interfacial tension to zero where complete miscibility is achieved (MMP).

Oil Swelling

Crude oil swells when contacted with carbon dioxide. Figure 3.4 shows the increase in oil volume as it becomes saturated with carbon dioxide. Injection of carbon dioxide artificially increases the oil formation volume factor. At the end of carbon dioxide injection, the final oil formation volume factor [B_{of}] is significantly increased, thus enhancing the mobilization efficiency. Blowdown recovery reduces B_{of} but the oil does not fully shrink back to its original volume[43]. At elevated pressures, B_{of} may also be increased by the stripping of components of the oil into the vapour phase[3].

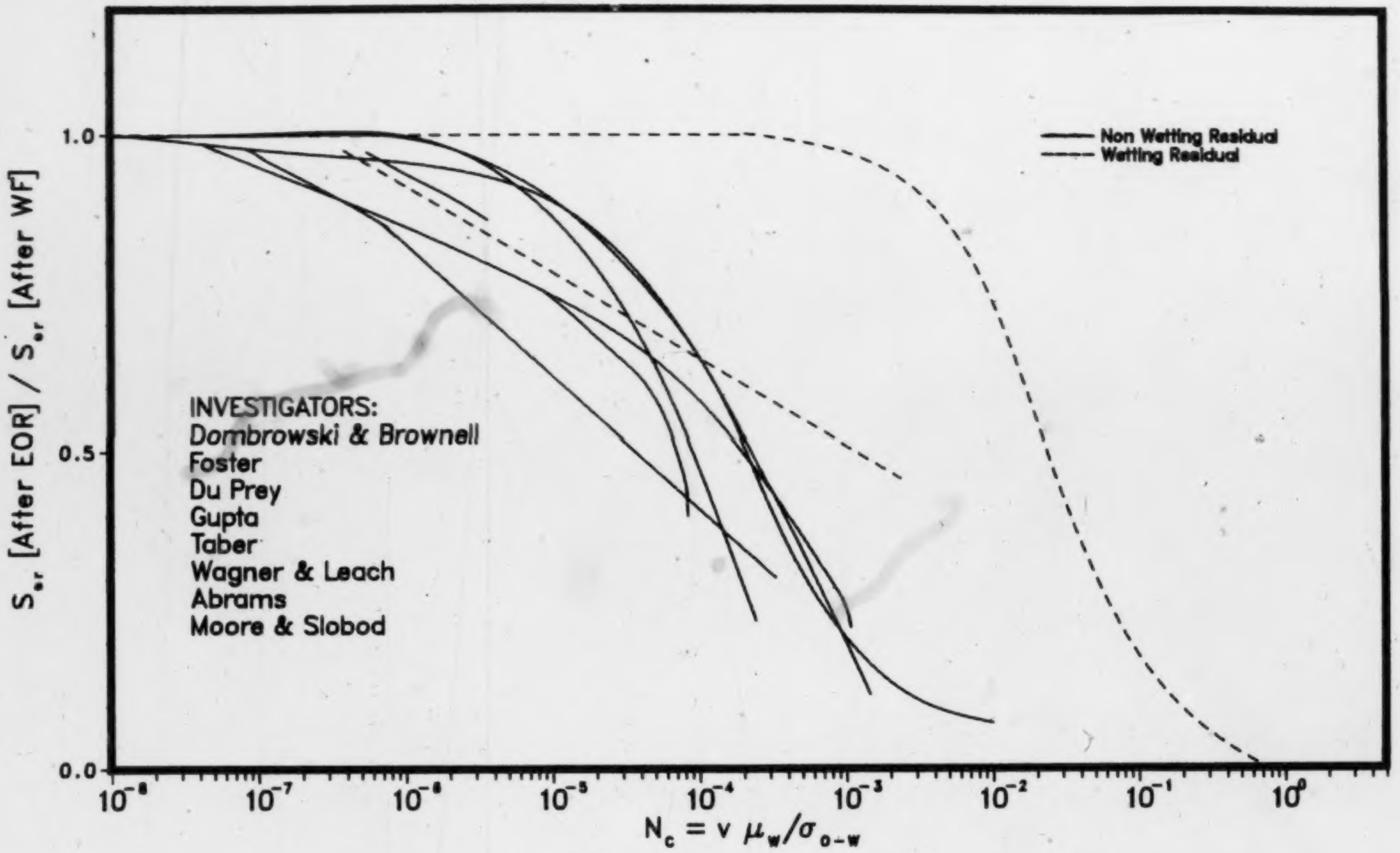


Figure 3.11 – Recovery of Residual Oil vs. Capillary Number, After Klins [Ref. 3].

Carbon Dioxide / Water Injection Strategies

As noted in the previous discussion, carbon dioxide alone cannot displace viscous oils efficiently, thus the carbon dioxide process must be supplemented with a mobility control mechanism. Several injection schemes using carbon dioxide and water have been suggested. Some of the more common ones are:

1. carbonated water injection (ORCO);
2. continuous carbon dioxide gas injection;
3. carbon dioxide gas, or liquid, slug followed by water;
4. simultaneous injection of carbon dioxide gas and water;
5. carbon dioxide gas, or liquid, followed by alternate water and CO_2 slugs;

Carbonated Waterflooding

Carbonated waterflooding was the first method attempted to inject carbon dioxide into the reservoir. For carbonated waterflooding (see Figure 3.12a) carbon dioxide diffuses out of the injected water carbon dioxide mixture when it contacts the reservoir oil. The diffusion process is slow relative to injecting pure carbon dioxide, thus an effective carbon dioxide concentration at the displacement front is absent[3]. Adverse mobility ratios will continue to exist due to the extremely low rate of oil viscosity reduction. Holm[1] conducted displacement experiments utilizing carbonated water and a single carbon dioxide slug on a 5 mPa•s crude oil. Figure 3.13 (After Ref. 1) shows that after 2 PV had been injected, the carbon dioxide slug process recovered approximately 30% more oil than the carbonated water process.

Continuous Carbon Dioxide Injection

In this process, carbon dioxide gas is injected continuously until a maximum gas-oil ratio, determined by project economics, is reached. This process is severely limited due to the lack of mobility and gravity control in heavy oil-carbon dioxide systems. Rojas[22]

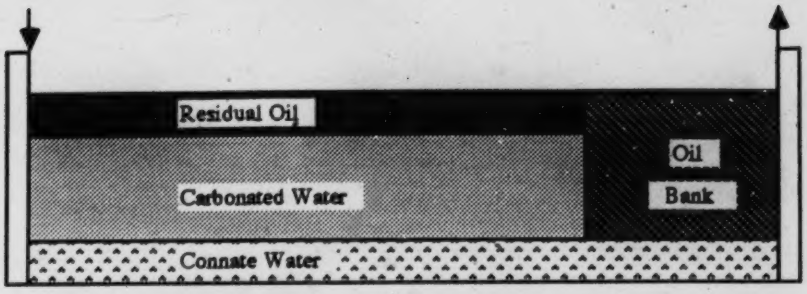

Residual Oil
Carbonated Water
Oil
Bank
Connate Water

Figure 3.12a : Carbonated Waterflooding (ORCO) Process

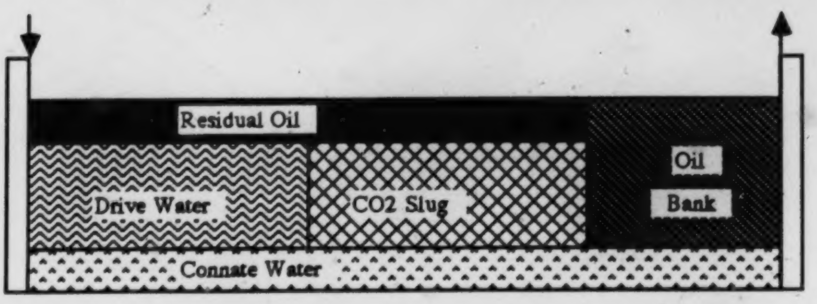

Residual Oil
Drive Water
CO2 Slug
Oil
Bank
Connate Water

Figure 3.12b : CO2 Slug and Water Drive Process

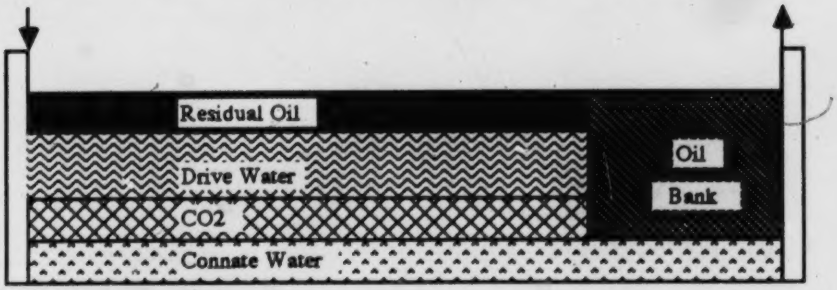

Residual Oil
Drive Water
CO2
Oil
Bank
Connate Water

Figure 3.12c : Simultaneous Water-CO2 Injection Process

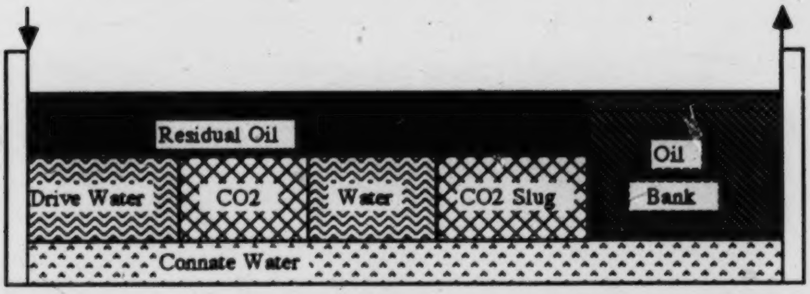

Residual Oil
Drive Water
CO2
Water
CO2 Slug
Oil
Bank
Connate Water

Figure 3.12d : Water-Alternating-CO2 (WAG) Process

Figure 3.12 - Schematic of CO2-Water Injection Strategies, After Klins [Ref. 3]

reported that, based upon scaled physical model studies, the carbon dioxide requirement, for the continuous carbon dioxide injection process, was up to ten times that of the WAG process. Sayegh and Maini[13] conducted displacement experiments in a linear core model. They found that the breakthrough recovery of a Lloydminster crude [23700 mPa•s @ 20 °C] by carbon dioxide at 3.45 MPa was as low as 3% PV. Garcia[74] reported a successful continuous carbon dioxide pilot test in the Oveja field of Venezuela. He found that this process worked well in a reservoir with a thick formation and good gravity segregation.

Simultaneous Carbon Dioxide and Water Injection

Warner[75] conducted simulation studies of various carbon dioxide injection strategies. He found that simultaneous injection of carbon dioxide and water yielded the highest oil recovery. Figure 3.12c is a schematic of the simultaneous water-carbon dioxide injection process. Several major problems exist with this process. First, the high completion and operating cost for dual injection systems. Second, reduced injectivity associated with the injection of two different phases, i.e. liquid and gas. Third, severe corrosion of the injection facilities, due to the acidic nature of carbon dioxide-water systems, reducing equipment life significantly.

Single Carbon Dioxide Slug Followed by Water

In the carbon dioxide slug process (see Figure 3.12b) a single carbon dioxide gas slug is injected and then followed by continuous water injection to drive the slug through the reservoir[3]. Rojas and Farouq Ali[2] reported very early carbon dioxide gas breakthrough in this process due to viscous instabilities (rapid viscous finger growth). Additional chase fluids, such as water, are needed to control the lack of gravity and mobility control. Rojas and Farouq Ali[2] also reported that this process is rate-dependent: the recovery during the gas injection phase decreased with a rise in carbon dioxide injection rate and increased during water injection.

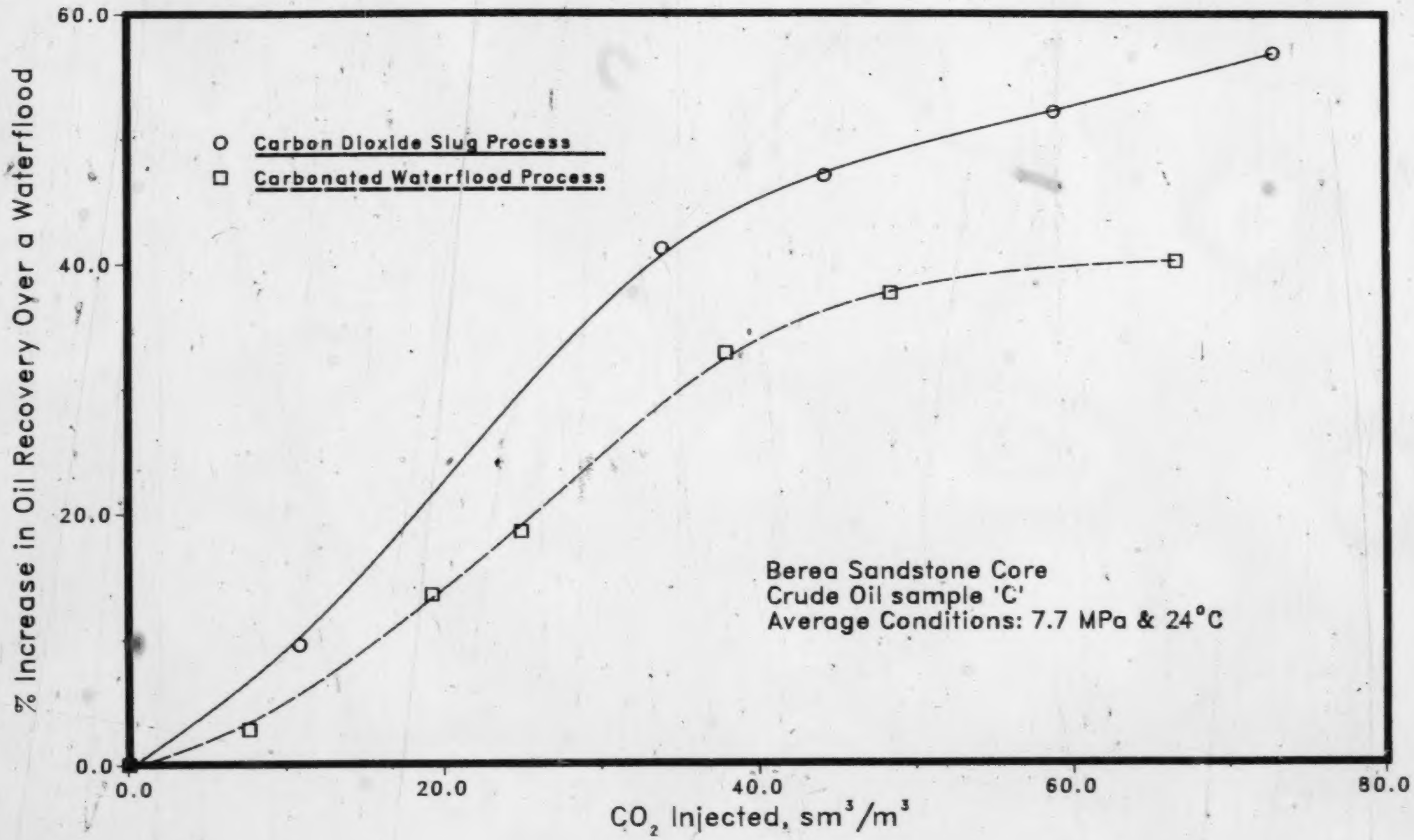


Figure 3.13 – Oil Recovery Using Carbonated Water and Carbon Dioxide Slugs, After Holm [Ref. 1].

Water-Alternating-Gas (WAG) Process

Another variation of the carbon dioxide slug process is illustrated in Figure 3.12d. In this process alternate slugs of carbon dioxide gas and water are injected until the desired volume of carbon dioxide has been achieved. The process is then followed by a waterflood to further displace the swollen, lower viscosity crude. The WAG ratio is the ratio of the total volume of water injected to the total volume of carbon dioxide injected at reservoir conditions. The single slug process may be visualized as having a WAG ratio of zero, while a waterflood may be visualized as an infinite WAG ratio process. Several investigators[1,2,3,15,22,75-77] have found that the WAG process successfully reduces the mobility ratio and promotes a more uniform distribution of carbon dioxide throughout the reservoir. Simulation studies conducted by Warner[75] showed that although the WAG process did not recover as much oil as the simultaneous injection process, it was economically more favourable and recovered more oil than the single and continuous carbon dioxide processes.

Huang and Holm[78] studied the effect of carbon dioxide WAG injection on rock wettability in miscible displacement experiments. Their results indicate that significant trapping of oil, due to the presence of injected water, occurs in preferentially water-wet rocks, and to a lesser degree in oil-wet rocks. They also found that the WAG process trapped more residual oil [≈10% PV] than the continuous or single slug tertiary processes in strongly water-wet rocks. In oil-wet rocks, the tertiary recovery was approximately equal for all the processes, and little trapping of oil was observed.

Tertiary Oil Recovery by Immiscible Carbon Dioxide Flooding

Oyekan[16] investigated the recovery of residual oil using carbon dioxide in a linear scaled physical model. His analysis of the problem showed that capillary forces are dominant in the trapping of oil but that by-passing of the residual oil may also result from gravity segregation, viscous fingering, heterogeneties, and differences in fluid mobilities. Mathematical analysis showed that the capillary pressure across the interface between oil and water, in a horizontal system, must be overcome before the residual oil droplets can be mobilized. Experimental results indicated that the injection rate of carbon dioxide influences the mobilization of residual oil and may also influence the ultimate residual oil recovered, viz. capillary number effects. Oyekan concluded that the dominant mechanism responsible for carbon dioxide recovery of residual oil is the solubility of carbon dioxide in oil. He found that increasing carbon dioxide solubility, by raising pressure, increased residual oil recovery, and that the natural gas in solution inhibited the ability of carbon dioxide to recover residual oil.

Sankur *et al* [79,80] investigated various immiscible carbon dioxide tertiary methods for the recovery of a 14°API (3000 mPa•s) oil in waterflooded cores. The authors found that the single carbon dioxide slug process recovered more oil than the carbon dioxide "huff-n-puff" process. Several WAG type runs were also conducted. They concluded that heavy oil tertiary recovery, and carbon dioxide utilization, could be improved by using smaller slugs of water alternating with carbon dioxide at high WAG ratios and pressures. Significant increases in residual oil recovery were attained for the WAG process with an increase in pressure from 5.2 to 8.6 MPa at temperatures up to 40°C.

Wang[81] investigated the effect of slug size and pressure on the tertiary recovery of a 16.9°API (130 mPa•s) oil using a slim tube system. He found that increasing the carbon dioxide slug size from 0.2 to 1.2 PV increased tertiary recovery slightly from 26.1 to 31.5%, but the carbon dioxide requirement (sm^3 CO_2/sm^3 oil produced) increased dramatically from 161 to 800. These results indicate that there is an economical, optimum, slug size for the tertiary recovery of heavy oil by the carbon dioxide drive process. Ko and Stanton[82] concluded, from numerical simulation studies on the WAG process, that larger alternating carbon dioxide slugs are required for the tertiary, as opposed to secondary, recovery of heavy oil. Both Wang[81] and Sankur *et al* [79] observed increasing tertiary oil recovery with increasing pressure at temperatures above the critical, viz. increasing carbon dioxide solubility.

Sayegh and Maini[13] conducted a laboratory investigation into the tertiary recovery of a 14.5°API (23700 mPa•s) oil using the "huff-n-puff" process at 3.5 MPa. Their results indicated that the presence of a low mobile water saturation (greater than S_{wirr}) resulted in the preferential displacement of water and subsequently little oil was displaced by the injected gas.

Bardon *et al*[83] investigated the efficiency of Dodan gas [≈88% CO_2] on the recovery of a 13°API oil in the Bati Raman field (Turkey) which had previously been waterflooded. Laboratory investigations conducted on waterflooded cores showed a 17 percentile decrease in residual oil saturation when flooded with a 10% PV slug of Dodan gas and waterflooded at 10 MPa.

Scaling of the Immiscible Carbon Dioxide Process

The processes occurring in heavy oil reservoirs, when injecting carbon dioxide and water to immiscibly displace oil, is basically fluid flow of three immiscible phases and mass transfer between carbon dioxide and water and between carbon dioxide and oil. In the zone invaded by carbon dioxide and water, mass transfer takes place due to solution, diffusion, and dispersion of carbon dioxide in oil and water, solution being the most important of all.

Derivation of the Scaling Groups

Rojas[22] derived the scaling groups for the immiscible displacement of oil by carbon dioxide and water by two methods: dimensional analysis and inspectional analysis. Langhaar[84] defined dimensional analysis as "a method by which information about a phenomenon can be deduced from the single premise that the phenomenon may be described by a dimensionally correct equation among certain variables". The dimensional analysis to derive the scaling groups for a process is based on the Buckingham π-Theorem[85]. Craig *et al*[86] defined inspectional analysis as, "all the equations describing the process mechanisms combined to form a single equation, and the coefficients of this equation are then combined to form the dimensionless scaling groups".

The partial differential equations for multiphase flow with mass transfer were derived by combining Darcy's and Fick's Laws, and the equation of mass conservation with the following assumptions[22]:

1. Homogeneous porous medium.
2. Immiscible Fluids.
3. Liquids are of small and constant compressibility at reservoir conditions.
4. Darcy's and Fick's equations are valid. Flow rates are small enough so that inertial effects are negligible.
5. Flow behavior of oil is Newtonian.
6. Relative permeabilities depend on saturation according to channel flow theory, i.e. pore size distribution, wettability, saturation history, and interfacial tension are constant in an isothermal displacement.
7. The reservoir temperature remains constant during carbon dioxide and water injection.
8. Three phases may exist and are in instantaneous equilibrium: an oleic phase, an aqueous phase, and a carbon dioxide gas phase.
9. Mass transfer between carbon dioxide - oil, and carbon dioxide - water occurs only by solution.
10. There is no transfer of oil or water into the carbon dioxide gas phase.

Table 3.1 summarizes the comparison of the scaling groups derived by inspectional analysis and dimensional analysis.[22] Recently Lozada and Farouq Ali[87] derived a new set of scaling criteria for a more comprehensive description of the process, which accounts for diffusion and dispersion, and thus partial phase equilibrium.

Table 3.1

Comparison of the Scaling Groups Derived by Inspectional and Dimensional Analyses, After Rojas [Ref. 22]

Number	Scaling Group	Derived by Inspectional Analysis	Derived by Dimensional Analysis	Name
1	L/W	Yes	Yes	Geometric Factor
2	L/H	Yes	Yes	Geometric Factor
3	$\frac{k_{rg}(S_w^*)\,\mu_o}{k_{ro}(S_g^*;\,S_w^*)\,\mu_w}$	Yes	Yes	Gas-Oil Ratio of Viscous Forces
4	$\frac{k_{rw}(S_w^*)\,\mu_o}{k_{ro}(S_g^*;\,S_w^*)\,\mu_w}$	Yes	Yes	Water-Oil Ratio of Viscous Forces
5	$\frac{g\,k\,\Delta\rho_{og}}{v\,\mu_g}$	Yes	Yes	Gas-Oil Ratio of Gravitational to Viscous Forces
6	$\frac{g\,k\,\Delta\rho_{wo}}{v\,\mu_w}$	Yes	Yes	Water-Oil Ratio of Gravitational to Viscous Forces
7	$\frac{\sigma_{go}\sqrt{k\,\phi}}{L\,\mu_g\,v}$	Yes	Yes	Gas-Oil Ratio of Capillary to Viscous Forces
8	$\frac{\sigma_{ow}\sqrt{k\,\phi}}{L\,\mu_w\,v}$	Yes	Yes	Water-Oil Ratio of Capillary to Viscous Forces
9	$\frac{D_{goy}\,L}{W^2\,\lvert v_T\rvert}$	Yes	Yes	Gas in Oil Transverse Dispersion Scaling Group
10	$\frac{D_{gwy}\,L}{W^2\,\lvert v_T\rvert}$	Yes	Yes	Gas in Water Transverse Dispersion Scaling Group
11	$\frac{D_{goy}\,L}{D_{gox}\,W}$	Yes	Yes	X - Y Gas in Oil Dispersion Similarity Group
12	$\frac{D_{goz}\,L}{D_{gox}\,H}$	Yes	Yes	X - Z Gas in Oil Dispersion Similarity Group

Table 3.1 (Continued)

Comparison of the Scaling Groups Derived by Inspectional and Dimensional Analyses, After Rojas [Ref. 22]

		Derived by		
Number	Scaling Group	Inspectional Analysis	Dimensional Analysis	Name
13	$\frac{D_{gwy} L}{D_{gwx} W}$	Yes	Yes	X - Y Gas in Oil Dispersion Similarity Group
14	$\frac{D_{gwz} L}{D_{gwx} H}$	Yes	Yes	X - Z Gas in Water Dispersion Similarity Group
15	$\frac{\rho_g v \sqrt{k}}{\mu_g}$	No	Yes	Gas Reynolds Number
16	$\frac{\rho_w v \sqrt{k}}{\mu_w}$	No	Yes	Water Reynolds Number
17	V_w^* / V_g^*	No	Yes	Water-Gas Ratio of Slug Volumes
18	ϕ	No	Yes	Porosity Factor
19	$\mathcal{M}$	No	Yes	Morphology Factor
20	$k_{rg} (S_g^*)$	Yes	Yes	Gas Relative Permeability Factor
21	$k_{ro} (S_g^*: S_w^*)$	Yes	Yes	Oil Relative Permeability Factor
22	$k_{rw} (S_w^*)$	Yes	Yes	Water Relative Permeability Factor
23	$J(S_g^*)$	No	Yes	Gas-Oil Leverett J-Function Factor
24	$J(S_w^*)$	No	Yes	Oil-Water Leverett J-Function Factor
25	$\frac{dJ(S_g^*)}{dS_g^*}$	Yes	No	Gas-Oil Leverett J-Function Slope Factor
26	$\frac{dJ(S_w^*)}{dS_w^*}$	Yes	No	Oil-Water Leverett J- Function Slope Factor

Relaxation of Scaling Requirements

In practice, generally it is not possible to satisfy all of the dimensionless groups simultaneously. However, in any particular application, not all of the scaled parameters are important.

When the sand in the model and prototype are both unconsolidated, the morphology scaling factor is believed to be satisfied. Geertsma[88] indicated that when flow is laminar, the influence of the visco-inertial forces is not significant. Rojas[22] calculated the critical superficial velocity of carbon dioxide to be 2.74 m/d for the Aberfeldy prototype. Pujol and Boberg[89] pointed out that when dealing with the displacement of highly viscous oils from unconsolidated sands, capillary forces do not need to be scaled. They concluded that for heavy oils, the ratio of capillary to viscous forces is so low that unscaled capillary pressures have a negligible effect on the oil recovery behaviour.

Engelberts and Klinkenberg[90] discussed the phenomenon of end effect in laboratory models. The end effect is due to a discontinuity in capillary properties at the outflow end of the model. This discontinuity occurs when the fluids pass abruptly from the sand, a region of finite capillary pressure, into an open receiving well, where capillary pressure vanishes. This results in an increase of the wetting phase saturation at the production boundary. Rojas[22] studied this effect for a gas-oil system and a water-oil system. He concluded that the end effect is negligible for the displacement of viscous oils in a relatively short system.

After relaxing the capillary and diffusive forces, and considering that the model and prototype have the same morphology, the same fluids, and are operated at the same conditions of pressure and temperature, the following scaling groups were completely satisfied: geometric groups, morphology group, ratio of gravitational to viscous forces, and water-gas ratio of slug volumes, when a moderate injection rate for carbon dioxide-water floods was used. The final set of scaling groups, after relaxation, derived by Rojas[22] is as follows:

$$L/W, \quad L/H, \quad M_{wo}, \quad M_{go}, \quad \phi, \quad \mathcal{M}, \quad V_w^*/V_g^*$$

$$\frac{g\,k\,\Delta\rho_{og}}{\nu\,\mu_g}, \quad \frac{g\,k\,\Delta\rho_{wo}}{\nu\,\mu_w}, \quad \frac{D_{Tgo}\,L}{W^2\,\nu}, \quad \frac{D_{Tgw}\,L}{W^2\,\nu}, \quad \frac{D_{Tgo}\,L}{D_{Lgo}\,W}, \quad \frac{D_{Tgw}\,L}{D_{Lgw}\,W}$$

If the model and prototype have the same morphology, the same fluids, and are operated at the same conditions of temperature and pressure, the requirements for scaling after relaxing the diffusive forces become[22]:

$$\frac{(L/H)_m}{(L/H)_p} = \frac{(L/W)_m}{(L/H)_p} = \frac{(k/\nu)_m}{(k/\nu)_p} = \frac{(V_w^*/V_g^*)_m}{(V_w^*/V_g^*)_p} = 1$$

These scaling factors were then used to determine the physical dimensions of the model, injection rates, and the slug volumes of carbon dioxide and water in order to obtain approximate similarity in recovery between the model and the prototype.

Rojas[22] conducted his investigation at high pressures in order to simulate accurately the mass transfer between carbon dioxide and the reservoir fluids, the chemistry of the process, and the in situ formation of emulsions. Various combinations of superficial velocities were also used in his investigation. Rojas pointed out that at low superficial velocities it is possible to scale down simultaneously geometric similarity, ratio of viscous forces, ratio of viscous to gravitational forces, and chemical similarity. At high superficial velocities it is possible to scale down simultaneously geometric similarities, ratio of viscous forces, lateral dispersion similarity group, and chemical similarity.

Simulation Studies of the Immiscible Carbon Dioxide Process

The complexity of the immiscible carbon dioxide displacement process makes it difficult to physically model all of the processes taking place. By combining both scaled physical model studies with numerical simulations, a better understanding of the processes will evolve.

Most numerical simulations of the immiscible carbon dioxide process are "black oil models". In this type of simulation, the hydrocarbon system is approximated by a multiphase system of oil, water, and gas (CO_2). In most cases dispersive mixing is assumed to be negligible. The major drawback associated with black oil models is the failure to account for the intimate mixing of gases, particularly natural gas, if present in significant quantities. Several investigators[10,91-93] have simulated the immiscible carbon dioxide flooding process utilizing variations of the black oil model.

Klins and Farouq Ali[96] designed an unsteady-state two-dimensional, three phase (oil, water, CO_2) simulator. They assumed no diffusional mixing and thermodynamic equilibrium between all phases. Their results indicated that over an oil viscosity range of 70 to 1000 mPa•s, and pressure range of 7 to 7.5 MPa, carbon dioxide flooding was superior to natural depletion, nitrogen flooding, and waterflooding. They also found that for oil viscosity in the range of 100 to 1000 mPa•s, oil recovery was a strong function of initial oil saturation. For the 1000 mPa•s oil, recovery increased 26 percentiles when the initial oil saturation was increased from 40 to 70%. The authors concluded that the carbon dioxide flooding process must be assisted by a mobility control mechanism to enhance recovery significantly.

Patton *et al* [10] simulated the carbon dioxide "huff-n-puff" process and history matched their results to a single well pilot test. The model numerically simulated two- or three-dimensional flow by implicitly solving the Darcy flow and mass conservation equations. The implicit formulation and direct solution method was necessary in order to accurately simulate the rapid, large pressure transients encountered in the carbon dioxide cyclic stimulation process. The authors employed multiple regression analysis to correlate the 200 data points in an attempt to describe the process efficiency. The results of the regression analysis is given by Equation (3.14). The authors reported that the coefficient of regression [R^2] indicated 67 percent of the variation in the data had been described.

$$E = 0.33 - 0.35\ N_{cyc} - 4.5 \times 10^{-5}\ \mu_o + 1.6 \times 10^{-4}\ p_t + 1.3 \times 10^{-9}\ p_t^2$$
$$+ 4.3 \times 10^{-5}\ k - 0.013\ S_{oi} - 0.69\ V_{cyc} \qquad (3.14)$$

where,

E = process efficiency, [sm^3 incremental oil/sm^3 CO_2 Inj]
N_{cyc} = number of cycles [–]
μ_o = oil viscosity, [mPa•s]
p_t= treatment pressure, max BHP, [kPa]
k = reservoir permeability, [md]
S_{oi} = initial oil saturation, [fraction]
V_{cyc} = volume of CO_2 inj/cycle/meter of pay, [sm^3/m]

The authors concluded that the carbon dioxide "huff-n-puff" process would be most economical under the following optimal conditions: oil viscosities less than 2000 mPa•s (at reservoir conditions), no flow blockages around the wellbore, deep reservoirs capable of accepting high pressures, and water-wet reservoirs. An interesting phenomenon noted by the authors was that the first cycle, regardless of the volume of carbon dioxide injected, was always the most productive in terms of oil produced relative to carbon dioxide injected.

Reid and Robinson[91] conducted simulation studies on the Lick Creek Meakin Sand Unit reservoir, Arkansas. Their numerical model employed a three-dimensional, three-phase compressible hydrocarbon system for a multi-layered reservoir. Their results indicated that the WAG process with cyclic stimulation of the producing wells, and recycling of the produced carbon dioxide, would be the most economically attractive for the field. The results also indicated the highest residual oil saturation occurred in the upper layer, which was swept by carbon dioxide but not by water because of gravity override. According to the results, carbon dioxide stimulation of the producing wells, implemented prior to the WAG process, would improve oil rates, reduce water-oil ratios, increase carbon dioxide sweep of both layers, and disperse carbon dioxide rapidly throughout the reservoir. Subsequent history matching of the simulation runs to the field has not yet been conducted.

Mansoori[92] developed a compositional simulator to investigate the effects of carbon dioxide-water solubility on oil recovery by carbon dioxide flooding. The numerical model simulated both one and two-dimensional multiphase flow by implicitly solving the Darcy flow and mass conservation equations. Phase behaviour calculations were performed on the basis of equality of component fugacities among all three equilibrium phases. Henry's Law was used to account for carbon dioxide solubility in water. For both the one- and two-dimensional simulations, the effect of solubility of carbon dioxide in water was found to be significant (see Figure 3.14).

Sigmund *et al*[93] designed a multi-layered compositional simulator to demonstrate how variations in phase behaviour representation could influence the relative importance of extraction, swelling, and viscosity reduction on displacement efficiency. The basis of their four-component finite difference model is described by Gardner *et al*[94] and Orr *et al*[95]. The simulator was then calibrated against measured phase behavior data from slim tube experiments on fluids from the Retlaw Mannville V Pool, Alberta. Comparison of the data by an eleven-component Peng-Robinson equation-of-state [PREOS] with those observed experimentally indicated that a ternary representation with K-values that obey Hand's rule can adequately approximate the actual phase behaviour. Their results indicated that a 25% PV slug of carbon dioxide at 11.8 MPa followed by water recovered approximately 20-25% more oil than a conventional waterflood.

Spivak and Chima[64] also used an equation-of-state simulator to assist in the design and monitoring of several projects in the Wilmington Field, California. The immiscible carbon dioxide process was visualized as one of viscosity reduction, followed by waterflooding of the viscosity reduced oil. Simulation results indicated that the WAG process, as opposed to single slug injection, resulted in increased recoveries with better carbon dioxide utilization.

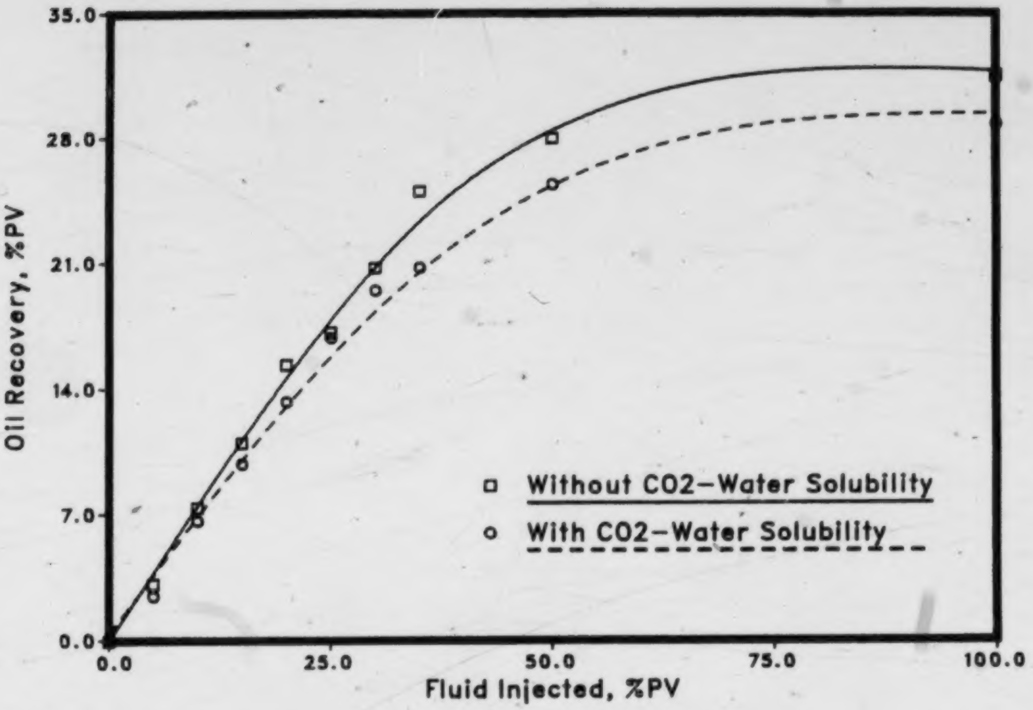


Figure 3.14a – Effect of Carbon Dioxide-Water Solubility on Oil Recovery [1-D], After Mansoori [Ref. 92].

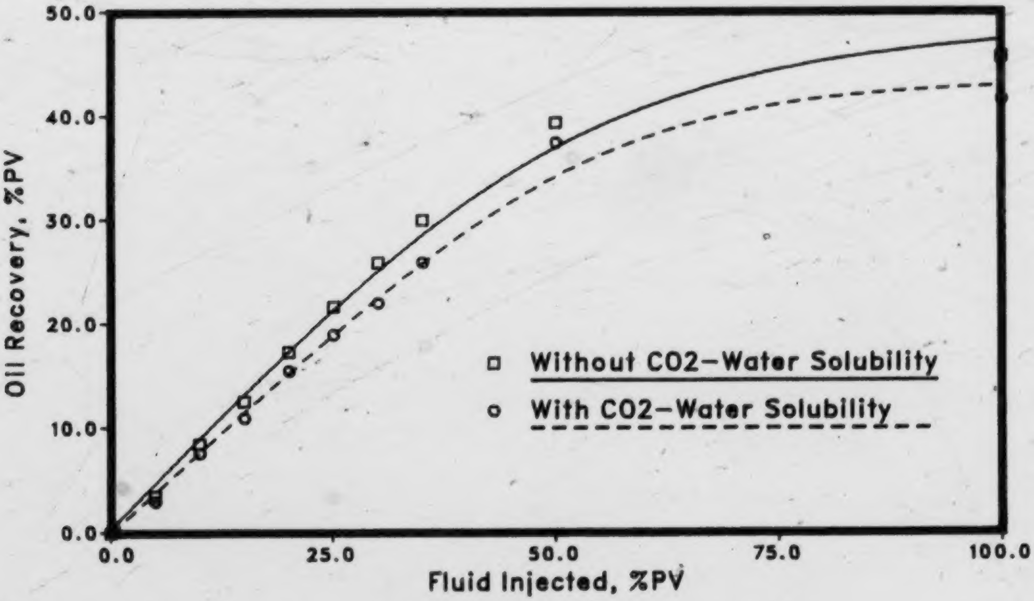


Figure 3.14b – Effect of Carbon Dioxide-Water Solubility on Oil Recovery [2-D], After Mansoori [Ref. 92].

Immiscible Carbon Dioxide Field Projects

Pilot testing of the immiscible carbon dioxide process began as early as 1949 in New York State by the Bradely Producing Corporation. The first tests utilized carbonated water injection. The results were discouraging but several important features of the process were discovered[97]:

1. additional oil was recovered;
2. the ORCO process caused no serious corrosion problems
3. injection capacity of a five-spot was increased;
4. scale deposits of barium sulphate occurred in several producers
5. a noticeable increase in natural gas production was observed, and
6. the presence of barium sulphate and unsaturated hydrocarbons suggested a chemical reaction had taken place in the reservoir.

The first full scale ORCO flood, which essentially involved carbonated water injection, was conducted by the Oil Recovery Corporation in 1958 in Bartlesville, Oklahoma. The ORCO flood was marginally successful but not economically feasible due to the tremendous cost of transporting and processing the carbon dioxide.

The first injection of gaseous carbon dioxide was conducted in the Ritchie Field of southern Arkansas in 1969. This process had previously been patented by P.C. Keith (an associate of U.S. Oil and Refinery Company)[97] and was considered a localized stimulation process or cyclic single-well ("huff-n-puff") stimulation.

Approximately eighty other immiscible carbon dioxide projects have been reported in the literature[98-100]. The majority of the projects employed the localized stimulation, cyclic single-well, while some others used the more conventional flooding patterns utilizing the water-alternating-gas [WAG] process. Leonard[99] presented many immiscible carbon dioxide projects which are presently in the planning stages. Discrepancies were reported for some field tests regarding the process under which the field was operating.

Reservoir Characteristics and Fluid Properties

Reservoir characteristics and fluid properties vary widely among the field tests reported. Table 3.2 presents the formation and fluid properties for all of the immiscible carbon dioxide projects found in the literature. Detailed data in the tables were taken from Pande[98], which provided an excellent source of information on most of the immiscible as well as miscible projects reported throughout the world.

The vast majority of field studies have been carried out in sandstone lithologies, with a few tests conducted in dolomite or limestone formations. Depths vary from 183 to 3962m with the majority in the 1500 to 2000m range. Most formations undergoing immiscible carbon dioxide flooding are 10m or less in thickness, with several in the range of 30 to 64m. There is no correlation of the depth/thickness ratio. Porosities vary from 2 to 37% with the majority in the 25 to 30% range. Permeability variation among the fields is extremely large and no particular range of optimal permeability is apparent. Reservoir temperatures for the most part fall in the range of 45 to 70°C while initial reservoir pressures vary from 7 to 27 MPa with the majority in the range of 8 to 17 MPa.

Fluid properties are slightly more consistent than the formation characteristics. The majority of hydrocarbons exploited by the immiscible carbon dioxide displacement process are in the range of 10 to 25°API with viscosities varying widely. Note that the Amoco project at Gregoire Lake has a crude oil viscosity greater than 100,000 mPa•s at 10°C. Amoco plans to inject steam and carbon dioxide in this project. Most fields, after undergoing primary production, began with an oil saturation between 30 and 60% of the original oil in place [OOIP] before the immiscible carbon dioxide process was initiated.

Table 3.2 (SI)
Immiscible CO2 Field Projects (Refs. 98-100)

Initation Date —	Operator / Field — —	Formation Depth (m)	Formation Thickness (m)	Formation Lithology —	Formation Porosity (%)	Formation Permeability (µm2)	Oil Gravity (°API)	Oil Viscosity (mPa•s)	So — (%)	Sw — (%)	Reservoir Temp. (°C)	Initial Res. Pressure (MPa)	Flood Pattern —
03/87	Texaco/Bay De Chene*	2286	—	—	—	—	34.0	—	—	—	—	—	—
03/87	Texaco/Delacroix*	2408	—	—	—	—	38.0	—	—	—	—	—	—
03/87	Texaco/Lake Pelto*	2560	—	—	—	—	31.0	—	—	—	—	—	—
02/87	Texaco/Golden Meadow*	3078	—	—	—	—	37.0	—	—	—	—	—	—
02/87	Texaco/Bayou Fer Blanc*	4115	—	—	—	—	39.0	—	—	—	—	—	—
02/87	Texaco/Lafitte*	1219	—	—	—	—	21.5	—	—	—	—	—	—
01/87	Texaco/Lafitte*	1981	—	—	—	—	25.9	—	—	—	—	—	—
01/87	Texaco/Lafitte*	1326	—	—	—	—	28.0	—	—	—	—	—	—
06/86	Texaco/West Nancy*	4206	—	—	—	—	38.2	—	—	—	—	—	—
06/86	Texaco/Vermilion*	1585	—	—	—	—	40.5	—	—	—	—	—	—
06/86	Texaco/Vermilion*	1676	—	—	—	—	40.0	—	—	—	—	—	—
06/86	Texaco/Vermilion*	1829	—	—	—	—	33.5	—	—	—	—	—	—
05/86	Texaco/West Delta 109*	3200	—	—	—	—	39.0	—	—	—	—	—	—
05/86	Texaco/West Delta 109*	2987	—	—	—	—	37.5	—	—	—	—	—	—
05/86	Texaco/West Delta 109*	3033	—	—	—	—	38.3	—	—	—	—	—	—
05/86	Texaco/West Delta 109*	3779	—	—	—	—	31.3	—	—	—	—	—	—
05/86	Texaco/Caillou Island*	3932	—	—	—	—	33.6	—	—	—	—	—	—
05/86	Texaco/Caillou Island*	3901	—	—	—	—	33.5	—	—	—	—	—	—
04/86	Texaco/West Delta 109*	2652	—	—	—	—	38.3	—	—	—	—	—	—
04/86	Texaco/West Delta 109*	2918	—	—	—	—	38.1	—	—	—	—	—	—
04/86	Texaco/West Delta 109*	3200	—	—	—	—	37.1	—	—	—	—	—	—
04/86	Texaco/West Delta 109*	3048	—	—	—	—	37.4	—	—	—	—	—	—
04/86	Texaco/Leeville*	2194	—	—	—	—	36.1	—	—	—	—	—	—
04/86	Texaco/Caillou Island*	4267	—	—	—	—	37.1	—	—	—	—	—	—
02/86	Texaco/Boutte*	3130	—	—	—	—	37.0	—	—	—	—	—	—
02/86	Texaco/Bonnet Carre*	2865	—	—	—	—	37.0	—	—	—	—	—	—
1986	Westgrowth/Little Bow*	1067	—	—	—	—	25.0	—	—	—	—	—	—
12/85	Chevron/Timbalier Bay	1486	—	sandstone	32.0	0.49 - 2.46	26.0	17	60.0	40.0	59.0	—	—
11/85	Marathon/Yates	335-518	—	dolomite	17.0	0.017	30.0	5.5	—	—	27.8	—	—
10/85	Amoco/San Andres	1312	—	dolomite	13.0	0.001	32.0	—	—	—	37.8	—	—
06/85	Texaco/West Delta 109*	3048	—	sandstone	27.0	0.202	37.3	0.26	50.0	—	90.0	—	—
09/85	Amoco/Prentice NE	1813-2042	21.3-29.6	dolomite	5.7-12.4	(2.0-6.8)E-3	28.0	—	—	—	46.7	—	5-spot

* indicates planned projects

Table 3.2 (SI) cont.
Immiscible CO2 Field Projects (Refs. 98-100)

Initation Date —	Operator / Field — —	Formation Depth (m)	Formation Thickness (m)	Formation Lithology —	Formation Porosity (%)	Formation Permeability (µm2)	Oil Gravity (°API)	Oil Viscosity (mPa•s)	So % (%)	Sw % (%)	Reservoir Temp. (°C)	Initial Res. Pressure (MPa)	Flood Pattern —
06/85	Texaco/West Delta109*	3200	—	sandstone	30.0	1.875	36.5	0.28	50.0	—	93.3	—	—
06/85	Texaco/West Delta 109*	3657	—	sandstone	27.0	1.019	34.1	0.25	50.0	—	103.3	—	—
06/85	Texaco/West Delta 109*	3200	—	sandstone	29.7	0.067	37.0	0.3	50.0	—	98.9	—	—
06/85	Texaco/S.Marsh Island B6	3414	—	sandstone	29.6	0.319	34.0	0.3	50.0	—	97.8	—	—
1985	AGIP/Pisticci	1981	—	dolomite	18.0	0.197-0.493	11.0	23	60.0	40.0	67.2	—	1-spot
12/84	AGIP/Ponte Dirillo	2895-2956	—	dolomite	5.0-6.4	—	10-15	30	—	—	99.4	—	—
04/84	Texaco/Lake Barre	3962	39.6	sandstone	25.0	0.138	33.0	0.4	—	—	113.3	—	1-spot
02/84	Union Pacific/Wilmington	762	—	sandstone	24.0	0.458	14.0	283	51.0	49.0	50.6	—	—
1984	Texaco/Lafitte	2722-2744	4.9	—	27.0	0.247	32-33	0.7	—	—	—	27.21	1-spot
1984	Arco/Jeanerette	1829-1981	6.1-9.1	sandstone	30.0	—	36.0	0.5-0.8	—	—	73.9	—	1-spot
1984	Texaco/Bayou Sale	3048	3.4	—	30.0	0.148-1.579	34.0	0.38	—	—	93.3	—	1-spot
1984	Texaco/W.Cote Blanche	2438	13.1	—	29.0	0.271	28-30	0.8	—	—	82.2	—	1-spot
1984	Texaco/Liberty South	2371	9.1	sandstone	22.0	0.015	37.0	1.6	40.0	20.0	79.4	26.20	1-spot
1984	Amoco/Gregoire Lake	183	13.7	sandstone	20.0-35.0	—	5-8	100000	—	—	10.0	—	4-spot
1984	Pan Canadian/Lindbergh	610	7.6-12.2	sandstone	—	0.493-1.974	12.0	10000	—	—	22.8	—	1-spot
1984	TPAO/Camurlu	1250	64.0	dolomite	11.0-16.0	0 - 4.93E-3	10-12	284	77.0	23.0	74.4	12.41	1-spot
1984	TPAO/Bati-Raman	1311	64.0	dolomite	14.0-20.0	0.197-1.974	9-15	300-1000	79.0	21.0	65.6	12.41	1-spot
1984	Bow Valley/Cold Lake	457	24.4	sandstone	30.0	1.480	—	100000	—	—	15.6	—	7-spot
12/83	Gulf/Pittsburg	1052-1158	3.0	sandstone	23.0	0.233-0.887	14.0	2200	65.0	30.0	48.9	11.14	1-spot
12/83	Gulf/Heidelberg	1542	—	sandstone	25.0	0.073	20.0	15	—	—	65.6	—	1-spot
12/83	Chevron/Heidelberg	1542	—	sandstone	25.0	0.073	20.0	15	—	—	65.6	—	1-spot
11/83	Chevron/Pittsburg	1052-1158	3.0	sandstone	23.0	0.233-0.887	14.0	2200	65.0	30.0	48.9	11.14	1-spot
11/83	Westgrowth/Retlaw	--	1.8-2.4	sandstone	18.0	0.049	23.0	8-10	—	—	35.6	11.38	7-spot
10/83	Texaco/Plymouth	1419	—	sandstone	31.0	0.345	23.3	2.3	31.5	30.8	63.3	14.16	1-spot
08/83	XTRA/Wilmington FB1	1036	11.3	sandstone	28.0	0.099-0.987	14.0	179	66.0	34.0	58.9	8.96	—
08/83	Santa Fe Energy/Raymond	2408	2.7-6.7	dolomite	8.2	0.013	40.0	0.43	71.3	—	86.7	—	—
07/83	Texaco/West Columbia	792	45.7	sandstone	30.0	0.553	30.0	8	36-48	15.0	46.1	9.96	1-spot
07/83	Texaco/Magnet Withers	1660	20.4	sandstone	23.0	0.295-19.73	26.0	2.3	35.0	27.2	67.8	17.29	1-spot
06/83	Exxon/Pewitt Ranch	1378	15.2	sandstone	24.0	0.987-1.480	19.0	21-30	65.0	20.0	71.1	13.07	1-spot
05/83	Texaco/Pickett Ridge	1402-1426	2.7	sandstone	30.0	0.136-1.184	25.0	2.5	29.0	20.0	58.9	14.72	1-spot
05/83	Texaco/Talco	1154	7.6	sandstone	25.0	0.383	23.0	20-25	50.0	20.0	63.9	4.48	1-spot
03/83	Texaco/Withers, North	1600-1634	2.1	sandstone	25.0	1.036-3.223	25.7	2.45	35.0	20.0	62.8	16.88	1-spot
05/83	Texaco/Withers C-sand	1617-1621	2.4	sandstone	25.0	0.395-3.223	25.3	2.9	32.0	20.0	63.9	16.72	1-spot

Table 3.2 (SI) cont.
Immiscible CO2 Field Projects (Refs. 98-100)

Initation Date —	Operator / Field — —	Formation Depth (m)	Formation Thickness (m)	Formation Lithology —	Formation Porosity (%)	Formation Permeability (μm2)	Oil Gravity (°API)	Oil Viscosity (mPa•s)	So % (%)	Sw % (%)	Reservoir Temp. (°C)	Initial Res. Pressure (MPa)	Flood Pattern —
01/83	Texaco/Thompson	1554	7.6	sandstone	27.0	0.099-0.987	25.2	2.7	42-65	27.0	57.2	16.86	1-spot
01/83	Texaco/Pierce Ranch	1496	3.7	sandstone	24.4	0.011-1.924	24.4	8.56	48.0	31.0	68.3	14.30	1-spot
10/82	Texaco/Manvel F.B.I.	1524	6.1	sandstone	30.0	0.987	26.7	7.2	45.0	15.0	65.0	16.48	1-spot
10/82	Texaco/Manvel, East (3)	1219-1244	4.9	sandstone	30.0	0.395-0.493	25.0	4.4	42-65	15.0	65.0	13.20	1-spot
07/82	Union Texas Pet./Wellman	2835-2987	61.0-103.0	dolomite	8.0-9.6	0.001-0.987	43.0	0.5-0.7	55.0	22.0	66.1	27.72	—
06/82	Husky/Wainwright	457	4.1	sandstone	37.0	0.987-1.974	12.0	2000	—	—	21.1	—	1-spot
06/82	UNOCAL/East Coyote	914-1524	76-122	sandstone	—	—	16-26	—	—	—	—	—	--
03/82	LBODC/Wilmington FB5	701	15-30	sandstone	30.0	0.099-0.987	13-15	200-500	57.0	25.0	48.9	6.90	line-drive
02/82	Cities Service/Welch	1478-1554	30.5	carbonate	9.25-13.2	0.001-0.014	34.0	2.38	47.0	27.0	35.6	—	—
1982	? / Bradu (Rumania)	1016	7.0	sandstone	25.0	0.247	24.0	18	--	--	40.0	—	—
11/81	Aminoil/Huntington Bc.	762	—	sandstone	24.0	0.247	18.0	175	--	--	54.4	—	1-spot
03/81	Champlin/Wilmington FB3	762-781	12.8	sandstone	24.0	0.459	14.0	283	51.0	25.0	50.6	7.55	—
03/81	Union Pacific/Wilmington	762	—	sandstone	24.0	0.458	14.0	283	51.0	49.0	50.6	—	—
02/81	Phillips/Vacuum	1372	—	dolomite	11.7	0.011	38.0	1	70.0	--	38.3	—	—
01/81	Petromac Inc./Rankin	2408	9.1-11.6	sandstone	27.0	0.296	37.0	0.6	55.0	35.0	88.9	24.48	inv 7-spot
1981	Husky/Kitscoty	549	—	sandstone	31.0	1.974	13.0	7000	—	—	21.1	—	1-spot
01/80	OKGT/Nagylengyel	2256	—	dolomite	2.0-3.0	0.987	16.0	92	—	—	48.9	—	gas cap
1980	Amerada Hess/Eutaw	1463-1585	4.6-4.9	sandstone	28.4	0.284-0.296	22.0	16	51.0	35.0	68.9	13.79	inv 5-spot
03/79	Elf Aquitaine/Grenade	2347	—	dolomite	—	—	11.0	1000	99.0	—	71.7	—	—
1979	Shell Western/Weeks Island	3890	—	sandstone	23.0-26.0	0.985-1.774	33.0	0.34-0.60	22.0	7.0	107.2	34.13	—
01/75	Phillips/Lick Creek	762-777	2.6	sandstone	30.3-33.0	1.184-1.480	17.0	160-188	55-68	32-45	45.6	8.27	irregular
04/72	Shell Western/Crossett	1615-1646	18.3-24.4	dolomite	22.0	(3.0-5.0) E-3	44.0	0.36-0.40	34.0	35.0	41.1	17.24	inv 9-spot
1969	U.S. Oil&Ref. Co/Ritchie	792	2.7	sandstone	31.0	2.714	16.0	195	80.0	20.0	52.2	8.62	irregular
1958	Oil Rec.Corp./Bartlesville	—	—	—	—	—	—	—	—	—	—	—	5-spot
1951	Bradely Prod. Corp./Reno	—	—	—	—	—	—	—	—	—	—	—	5-spot
09/49	Bradely Prod. Corp./ ?	—	—	—	—	—	—	—	—	—	—	—	5-spot

Operational Aspects

Both secondary and tertiary recovery methods have been used in the field tests and have performed satisfactorily. Almost all the fields had previously undergone primary production resulting in recoveries ranging from 20 to 30% OOIP. Operating pressures varied from 1.2 to 2.8 times the reservoir pressure at start of carbon dioxide injection in the hope of obtaining near miscible conditions.

Several different operational processes have been attempted in the field. The ORCO process, viz. carbonated water injection, was successful to a point but further analysis showed improved recoveries when injecting pure carbon dioxide[97].

The majority of projects, at least initially, began with the stimulation or cyclic single-well process. This was to re-pressurize the reservoir in the vicinity of the well and take advantage of the solubility of carbon dioxide in oil at elevated pressures. In some cases a soak period was instituted to increase the contact time between the carbon dioxide and the oil. This process is analogous to the "huff-n-puff" technique used in many thermal operations.

Patton *et al* [10] reported some key operating parameters for a profitable cyclic single-well carbon dioxide stimulation. The most important were:

1. volume of carbon dioxide injected per cycle;
2. number of cycles, and
3. back pressure during production.

In most cases reported[10,98] the effectiveness of carbon dioxide decreased with subsequent cycles. Two to three cycles appears to be the optimum in reported field tests[10,97,98].

Claridge[101] suggested that cyclic carbon dioxide stimulation has a narrower range of application than full scale carbon dioxide flooding. Carbon dioxide cyclic stimulation was reported to be more successful in reservoirs where inter-well communication was poor. In reservoirs where good inter-well communication is observed, a full scale carbon dioxide flood is favoured over the very localized cyclic single-well stimulation process[101]. The single-well process is reported to be very successful for light oil reservoirs, with viscosities less than 30 mPa•s, but has not been successful in unconsolidated heavy oil reservoirs[100].

The water-alternating-gas [WAG] process has also been tested in the field and has shown improved recoveries over the continuous injection process and the ORCO process[102]. The WAG process looks promising for heavy oil reservoirs. This is due to the improved mobility control resulting in a more efficient displacement and lower carbon dioxide requirements[98]. Injection of a continuous slug of carbon dioxide was tested in a few fields and found to be inefficient and uneconomical[97]. Massive processing facilities are required to make this type of project economical.

Performance and Economics

Several indicators are used to predict the performance and economic aspects of an immiscible carbon dioxide flood. Performance indicators such as initial increase in oil production and incremental oil recovery, due to carbon dioxide injection, show the operator if a field is responding to a particular enhanced oil recovery [EOR] technique favourably. Factors such as carbon dioxide requirement, carbon dioxide retention, cost, transportation and processing, are the key economic indicators.

The initial response due to carbon dioxide flooding is similar to that encountered in steamfloods[2,91]. Extensive data was not reported in this area but some reports[98] have shown initial oil production rates increasing from 65 to 2700% with an accompanying decrease in water production rate varying from 4.5 to 730%. These drastic changes in the respective production rates are somewhat shortlived. Production reverts to marginal increases depending on the cycle and soak times in the stimulation processes, and on the WAG ratios in flood pattern projects. Incremental oil recoveries have been projected to range from 0.04 to 17% OOIP.

Limited data was available for predicting the economic performance for all of the field projects presented. Some operators reported detailed information about their projects while others gave sparse information. Carbon dioxide required is defined as the ratio of standard volume of carbon dioxide required to produce an incremental reservoir volume of oil. This differs from the carbon dioxide utilization rate which incorporates the processing and re-injection of produced carbon dioxide. Carbon dioxide retention is the percentage of the total volume of carbon dioxide (standard conditions) injected which is not produced, excluding natural sources of carbon dioxide. Carbon dioxide requirements projections varied from 35 to 2900 sm^3/sm^3 with the majority in the range of 500 to 1000 sm^3/sm^3. Retentions generally were in the range of 65 to 80% of that injected.

Operational Problems

A variety of operational problems have been reported in the literature. The greatest concern to most operators was securing a viable source of carbon dioxide. The earliest sources of carbon dioxide came from dry ice, solid carbon dioxide, which was transported to the injection site for carbonated waterfloods[97]. More recently, several large pipelines have been constructed in the United States to supply the necessary volumes of carbon dioxide for such large scale projects. In several cases the processing of stack gas from a nearby refinery was implemented.

Corrosion problems, due to the formation of carbonic acid, have been minimized by utilizing some or all of the following procedures[91,103]:

1. production well flow lines constructed of fibreglass;
2. injection well tubing string internally coated with plastic;
3. batch treatment of injection wells with scale and corrosion inhibitors;
4. transportation of carbon dioxide and water in separate lines to the injector.

Treating and foaming problems have occurred due to the nature of crude oil, low gravity and high viscosity, plus the carbon dioxide trapped in the oil. Continuous addition of a defoamer at the tank batteries has helped to alleviate this problem. As well, considerable heat and chemicals are needed to separate the oil and water in some cases.

Excessive gas production and/or early gas breakthrough problems have been reported. The WAG process with a ratio above unity was found to be the best solution, with the added benefit of reduced excessive water production and improved injection profiles. Excessive water production was also reduced by maintaining a high back-pressure on the formation, this also reduced recompression costs on the reinjected carbon dioxide[10,103]. Gas channeling problems were successfully treated by the addition of a gelling agent to preclude gas migration through microfractures[91,98]. The combined use of steam and carbon dioxide injection is being considered for several of the low temperature, high viscosity reservoirs[98].

Range of Application

Immiscible carbon dioxide flooding is not a substitute for thermal or miscible EOR techniques. Target reservoirs for the application of immiscible carbon dioxide flooding are those with oil too heavy to achieve miscibility with carbon dioxide and too deep and/or thin for economic and practical application of thermal methods[97]. Thermal methods are more efficient in displacing residual oil in fields than the immiscible carbon dioxide process.

Immiscible carbon dioxide flooding projects are targeted for reservoirs with the following characteristics[3,97,104] :

Viscosity (at res. cond.)	mPa•s	100 - 1000
Oil Gravity	°API	25 - 10
Oil Density	kg/m^3	904 - 1000
Fraction of oil remaining to be flooded prior to EOR	%PV	> 50
Oil Content	m^3/ ha•m	> 750
Porosity x Oil Saturation	–	> 0.08
Depth	m	> 300
Thickness	m	< 10
Initial Reservoir Pressure	MPa	> 6.90
Permeability	μm^2	> 0.200

The above parameters are generalized and are by no means fixed limits on the applicability of the immiscible carbon dioxide process. It is also important to note that the criteria above must be weighed equally with geology and economic considerations for each particular field under study.

Klins[3] presented a table of qualitative observations for fields being screened for immiscible carbon dioxide flooding. Reservoirs exhibiting a homogeneous formation with thin pay zones and high dip are favourable. Low capacity and vertical permeability in horizontal reservoirs is also desirable. Reservoirs with a natural water drive, a major gas cap or a major fracture system should be avoided. Several authors[3,97,102,103] have reported that the most important criterion for a successful tertiary immiscible carbon dioxide flood is that a high oil saturation exist following a waterflood.

Heavy Oil Projects

Approximately twenty projects listed in Table 3.2 are heavy oil projects. Table 3.3 lists the heavy oil projects. Oil viscosities vary from 30 to 100,000 mPa•s and oil gravities vary from 5 to 20°API. The majority of these projects are immiscible by nature due to the extremely high pressures that would be required to achieve miscibility. The majority of heavy oil fields have initial pressures ranging from 8 to 11 MPa at depths of approximately 1000m. Several of the heavy oil fields are employing carbon dioxide injection in conjunction with steam, due to the extremely high viscosities encountered.

Table 3.3 (SI)
Immiscible CO2 Heavy Oil Field Projects (Refs. 98-100)

Initation Date —	Operator / Field — —	Formation Depth (m)	Formation Thickness (m)	Formation Lithology —	Formation Porosity (%)	Formation Permeability (µm2)	Oil Gravity (°API)	Oil Viscosity (mPa•s)	So % (%)	Sw % (%)	Reservoir Temp. (°C)	Initial Res. Pressure (MPa)	Flood Pattern —
1985	AGIP/Pisticci	1981	—	dolomite	18.0	0.197-0.493	11.0	23	60.0	40.0	67.2	—	1-spot
12/84	AGIP/Ponte Dirillo	2895-2956	—	dolomite	5.0-6.4	—	10-15	30	—	—	99.4	—	—
1984	Amoco/Gregoire Lake	183	13.7	sandstone	20.0-35.0	—	5-8	100000	—	—	10.0	—	4-spot
1984	Pan Canadian/Lindbergh	610	7.6-12.2	sandstone	—	0.493-1.974	12.0	10000	—	—	22.8	—	1-spot
1984	TPAO/Camurlu	1250	64.0	dolomite	11.0-16.0	0 - 4.93E-3	10-12	284	77.0	23.0	74.4	12.41	1-spot
1984	TPAO/Bati-Raman	1311	64.0	dolomite	14.0-20.0	0.197-1.974	9-15	300-1000	79.0	21.0	65.6	12.41	1-spot
1984	Bow Valley/Cold Lake	457	24.4	sandstone	30.0	1.480	—	100000	—	—	15.6	—	7-spot
12/83	Gulf/Pittsburg	1052-1158	3.0	sandstone	23.0	0.233-0.887	14.0	2200	65.0	30.0	48.9	11.14	1-spot
11/83	Chevron/Pittsburg	1052-1158	3.0	sandstone	23.0	0.233-0.887	14.0	2200	65.0	30.0	48.9	11.14	1-spot
08/83	XTRA/Wilmington FB1	1036	11.3	sandstone	28.0	0.099-0.987	14.0	179	66.0	34.0	58.9	8.96	—
06/82	Husky/Wainwright	457	4.1	sandstone	37.0	0.987-1.974	12.0	2000	—	—	21.1	—	1-spot
06/82	UNOCAL/East Coyote	914-1524	76-122	sandstone	—	—	16-26	—	—	—	—	—	—
03/82	LBODC/Wilmington FB5	701	15-30	sandstone	30.0	0.099-0.987	13-15	200-500	57.0	25.0	48.9	6.90	line-drive
11/81	Aminoil/Huntington Bc.	762	—	sandstone	24.0	0.247	18.0	175	--	--	54.4	--	1-spot
03/81	Champlin/Wilmington FB3	762-781	12.8	sandstone	24.0	0.459	14.0	283	51.0	25.0	50.6	7.55	—
1981	Husky/Kitscoty	549	—	sandstone	31.0	1.974	13.0	7000	—	—	21.1	—	1-spot
01/80	OKGT/Nagylengyel	2256	—	dolomite	2.0-3.0	0.987	16.0	92	—	—	48.9	—	gas cap
03/79	Elf Aquitaine/Grenade	2347	—	dolomite	—	—	11.0	1000	99.0	—	71.7	—	—
01/75	Phillips/Lick Creek	762-777	2.6	sandstone	30.3-33.0	1.184-1.480	17.0	160-188	55-68	32-45	45.6	8.27	irregular
1969	U.S. Oil&Ref. Co/Ritchie	792	2.7	sandstone	31.0	2.714	16.0	195	80.0	20.0	52.2	8.62	irregular

Chapter IV

Review of the Preceding Immiscible Carbon Dioxide Studies Leading to the Current Investigation

The following chapter is a discussion of the previous investigations on the immiscible carbon dioxide flooding process conducted at this university. The first group of experiments was conducted by Rojas[22] between 1983 and 1985. The second group of experiments was conducted by Zhu[15] between 1985 and 1987. The majority of the data given here was published in Reference 77.

Experimental Results

Table 4.1 lists the pertinent data for the 56 displacement experiments conducted previous to this work. The results of the present work have also been included for uniformity and comparison. The suffix of the run number indicates the investigator who conducted the experiment. All of the previous work was conducted with the two-dimensional model. While most of the experimental runs were started with an irreducible water saturation in the model, in several cases the model was waterflooded prior to the carbon dioxide flood. The operating pressure, in six of the runs, was 2.5 MPa, while it was 5.5 MPa in the remaining runs. Table 4.1 also gives the average velocity, and the volume of gas injected, in both pore volumes and molar basis. Also given is the theoretical volume of gas required to fully saturate the in-place oil at model conditions. The tabulated results give oil recovery, carbon dioxide retention, and most important, carbon dioxide requirement in terms of sm^3 of carbon dioxide injected per sm^3 of oil produced.

Carbon Dioxide Slug Process

In Runs 5R through 10R, 2Z and 12Z (Table 4.1), a single carbon dioxide slug was injected, followed by water injection. The slug size in all of these runs was 20% HCPV. The injection velocities of carbon dioxide and water were varied. In all runs, carbon dioxide

Table 4.1

Summary of All Immiscible Carbon Dioxide Displacement Experiments

Comments			Model Parameters					Experimental Parameters					Results		
Run # — —	Model Type LC/TD —	Process Description	Average Porosity [ø] (%)	Abs Perm [k] (darcies)	Oil Visc [μ] (mPa•s)	Water Sat [Swc] (%)	Oil Sat [Soi] (%)	Run Press [p] (MPa)	Ave Flow Vel (m/d)	CO2 Required to Saturate (HCPV)	CO2 Vol Inj (HCPV)	CO2 Moles Inj (g-mol)	CO2 Required — (sm3/sm3)	CO2 Retained — (% inj)	Total Recovery [T-Rec] (% HCPV)
1a R	TD	0.15 HCPV Waterflood (Tertiary)	43.70	10.13	4681	6.4	93.6	5.50	3.41	0.00	0.00	0.00	0.0	0.00	1.66
1b R	TD	1 CO2 Slug => 0.33 RHCPV WF & 0.38 m/d CO2	43.70	10.13	4681	7.9	92.1	5.50	3.41	0.75	0.04	0.27	38.0	32.41	9.11/9.26
3a R	TD	2.36 HCPV Waterflood (Tertiary)	44.90	10.15	1032	18.5	81.5	5.50	2.27	0.00	0.00	0.00	0.0	0.00	45.27
3b R	TD	1 CO2 Slug => 1.42 RHCPV WF & 2.22 m/d CO2	44.90	10.15	1032	55.4	44.6	5.50	2.27	0.79	0.31	2.08	40.5	62.93	25.26/46.17
4a R	TD	3.10 HCPV Waterflood & Tank Sand (Tertiary)	43.00	10.60	1032	26.4	73.6	5.50	2.31	0.00	0.00	0.00	0.0	0.00	54.40
4b R	TD	1 CO2 Slug => 1.52 RHCPV WF & 2.31 m/d CO2	43.00	10.60	1032	66.5	33.5	5.50	2.31	0.82	0.35	2.08	48.9	32.74	13.24/29.05
5 R	TD	1 CO2 Slug => 2.18 HCPV WF & Tank Sand	44.00	7.40	1032	11.7	88.3	5.50	2.27	0.77	0.19	1.40	32.9	36.96	54.97
6 R	TD	1 CO2 Slug => 2.32 HCPV WF	43.14	24.25	1032	11.4	88.6	5.50	0.18	0.77	0.20	1.42	47.3	54.19	39.15
7 R	TD	1 CO2 Slug => 0.66 HCPV WF	43.70	15.40	1032	9.9	90.1	5.50	0.20	0.76	0.21	1.47	70.3	84.03	26.35
8 R	TD	1 CO2 Slug => 1.90 HCPV WF	45.50	15.41	1032	9.0	91.0	5.50	2.90	0.76	0.20	1.53	48.4	25.22	38.31
9 R	TD	1 CO2 Slug => 2.06 HCPV WF & 1.66 m/d CO2	45.67	16.75	1032	9.0	91.1	5.50	1.05	0.76	0.20	1.54	55.3	64.76	33.54
10 R	TD	1 CO2 Slug => 2.13 HCPV WF & 0.72 m/d CO2	47.00	17.90	1032	12.3	87.7	5.50	2.32	0.77	0.20	1.52	40.4	19.95	45.91
11 R	TD	1.72 HCPV Waterflood	38.74	8.70	1032	11.7	88.3	5.50	0.87	0.77	0.00	0.00	0.0	0.00	32.39
12 R	TD	1 CO2 Slug => 1.84 HCPV WF & Tank Sand	48.05	4.90	1032	8.1	91.9	5.50	2.90	0.76	0.20	1.62	36.3	76.63	50.94
13 R	TD	1:1 WAG (5 CO2 Slugs)	43.52	11.90	1032	12.4	87.6	5.50	1.15	0.77	0.16	1.13	38.6	68.85	38.56
14 R	TD	1:1 WAG (10 CO2 Slugs)	41.19	10.91	1032	11.7	88.3	5.50	1.16	0.77	0.20	1.35	47.3	48.99	39.42
15 R	TD	3:1 WAG (10 CO2 Slugs)	43.22	11.72	1032	11.1	88.9	5.50	1.16	0.77	0.20	1.42	43.7	74.39	42.26
16 R	TD	4:1 WAG (10 CO2 Slugs)	44.40	14.91	1032	11.3	88.7	5.50	1.44	0.77	0.20	1.46	39.0	67.54	47.54
17 R	TD	5:1 WAG (10 CO2 Slugs)	42.78	12.42	1032	12.7	87.6	5.50	1.16	0.77	0.20	1.40	40.5	53.53	46.44
18 R	TD	6:1 WAG (10 CO2 Slugs)	43.71	14.11	1032	12.2	87.8	5.50	1.47	0.77	0.20	1.43	43.3	61.34	43.25
19aR	TD	1.71 HCPV Waterflood (Tertiary)	44.70	14.80	1032	14.3	85.7	5.50	1.43	0.00	0.00	0.00	0.0	0.00	35.19
19bR	TD	4:1 WAG (10 CO2 Slugs)	44.70	14.80	1032	44.5	55.6	5.50	1.43	0.78	0.20	1.42	38.1	63.73	13.53/20.87
20aR	TD	1.63 HCPV Waterflood (Tertiary)	44.91	14.81	1032	10.1	89.9	5.50	1.44	0.00	0.00	0.00	0.0	0.00	35.52
20bR	TD	1:1 WAG (10 CO2 Slugs)	44.91	14.81	1032	42.0	58.0	5.50	1.44	0.76	0.20	1.54	39.9	64.87	12.47/19.34
21aR	TD	1.66 HCPV Waterflood (Tertiary)	43.15	9.26	1032	11.9	88.1	5.50	0.88	0.00	0.00	0.00	0.0	0.00	33.75
21bR	TD	6:1 WAG (10 CO2 Slugs)	43.15	9.26	1032	41.6	58.4	5.50	0.88	0.77	0.20	1.41	40.1	50.36	12.56/18.95
22aR	TD	0.85 HCPV Waterflood (Tertiary)	41.99	9.66	4681	11.0	89.0	5.50	0.87	0.00	0.00	0.00	0.0	0.00	17.11
22bR	TD	4:1 WAG (10 CO2 Slugs)	41.99	9.66	4681	26.2	73.8	5.50	0.87	0.77	0.20	1.40	68.2	45.38	10.57/12.75
23 R	TD	4:1 WAG (10 CO2 Slugs)	42.14	9.34	4681	10.9	89.1	5.50	0.87	0.77	0.20	1.39	83.6	75.21	22.19
24 R	TD	1 CO2 Slug => 1.38 HCPV WF	44.06	11.51	4681	10.9	89.1	5.50	1.16	0.77	0.20	1.45	81.6	31.42	22.80

Table 4.1 (con't)

Summary of All Immiscible Carbon Dioxide Displacement Experiments

Comments			Model Parameters					Experimental Parameters					Results		
Run # — —	Model Type LC/TD —	Process Description	Average Porosity [ø] (%)	Abs Perm [k] (darcies)	Oil Visc [µ] (mPa•s)	Water Sat [Swc] (%)	Oil Sat [Soi] (%)	Run Press [p] (MPa)	Ave Flow Vel (m/d)	CO2 Required to Saturate (HCPV)	CO2 Vol Inj (HCPV)	CO2 Moles Inj (g-mol)	CO2 Required — (sm3/sm3)	CO2 Retained — (% inj)	Total Recovery [T-Rec] (% HCPV)
25 R	TD	4:1 WAG (10 CO2 Slugs) & Tank Sand	43.21	4.51	1032	12.2	87.8	5.50	0.44	0.77	0.20	1.40	42.2	94.73	43.93
2a Z	TD	1.70 HCPV Waterflood (Tertiary)	37.55	8.50	1032	10.3	89.7	5.50	0.78	0.00	0.00	0.00	0.0	0.00	32.46
2b Z	TD	1 CO2 Slug => 2.44 RHCPV WF	37.55	8.50	1032	39.4	60.6	5.50	0.78	0.76	0.20	1.27	47.9	35.70	10.77/15.95
3a Z	TD	1.77 HCPV Waterflood (Tertiary)	39.81	9.96	1032	10.2	89.8	5.50	0.78	0.00	0.00	0.00	0.0	0.00	29.57
3b Z	TD	4:1 WAG (10 CO2 Slugs)	39.81	9.96	1032	36.8	63.2	5.50	0.78	0.76	0.20	1.36	51.6	37.41	6.78/9.63
4 Z	TD	4:1 WAG (10 N2 Slugs)	46.51	11.18	1032	18.5	81.5	5.50	1.04	0.89 *	0.20 *	0.81 *	33.9 *	61.74 *	33.00
5 Z	TD	4:1 WAG (10 N2 Slugs)	40.40	11.99	1116	7.0	93.0	5.50	1.04	0.93 *	0.20 *	0.80 *	34.3 *	22.97 *	32.50
6 Z	TD	4:1 WAG (18 N2 Slugs)	47.04	15.79	1116	17.2	82.9	5.50	1.29	0.89 *	0.21 *	0.83 *	35.3 *	14.09 *	31.60
7 Z	TD	3:1 WAG (10 N2 Slugs)	41.85	16.81	1116	9.0	91.0	5.50	1.55	0.88 *	0.20 *	0.81 *	34.1 *	17.93 *	32.70
8a Z	TD	1.00 HCPV Waterflood (Tertiary)	38.55	9.65	1116	8.4	91.6	5.50	0.78	0.00	0.00	0.00	0.0	0.00	25.32
8b Z	TD	4:1 WAG (10 N2 Slugs)	38.55	9.65	1116	31.6	68.4	5.50	0.78	0.88 *	0.20 *	0.76 *	63.5 *	36.97 *	6.26/8.38
9 Z	TD	4:1 WAG (10 CO2 Slugs) & 1.32 HCPV N2 Preflush	42.08	17.58	1116	7.9	92.1	5.50	1.55	0.76	0.20	1.65	48.2	51.51	43.70
10 Z	TD	4:1 WAG (10 CO2 Slugs) & 4.33 HCPV CO2 Preflush	39.87	15.54	1116	7.5	92.5	5.50	1.29	0.76	4.53	31.40	758.9	13.28	58.20
11 Z	TD	4:1 WAG (10 CO2 Slugs) & 4.27 HCPV CO2 Preflush	40.85	17.40	1116	8.9	91.1	5.50	0.32	0.76	4.47	31.25	710.1	0.00	61.20
12 Z	TD	1 CO2 Slug => 2.48 HCPV WF	40.48	12.38	1116	7.6	92.4	5.50	2.07	0.76	0.20	1.43	60.3	23.76	33.00
13 Z	TD	4:1 WAG (10 CO2 Slugs)	38.71	5.27	1116	9.7	90.3	5.50	2.59	0.76	0.20	1.33	54.9	37.05	35.90
14 Z	TD	4:1 WAG (10 CO2 Slugs)	43.15	16.21	1116	10.1	89.9	5.50	1.55	0.76	0.40	2.94	89.2	30.22	43.70
15 Z	TD	0.1 HCPV CO2 => 0.1 HCPV N2 => 1.79 HCPV WF	41.12	14.90	1116	9.4	90.6	5.50	1.55	0.76	0.10	0.70	27.5	36.78	35.40
16 Z	TD	4:1 WAG (10 CO2 Slugs)	39.26	14.28	1116	9.5	90.5	5.50	1.55	0.76	0.20	1.34	45.1	45.82	43.00
17 Z	TD	4:1 WAG (9 CO2 Slugs)	42.31	18.36	1116	10.1	89.9	5.50	1.55	0.76	0.10	0.73	27.9	74.11	35.40
18 Z	TD	4:1 WAG (10 CO2 Slugs) & High Perm Streak	38.80	18.10	2107	11.5	88.5	5.50	1.55	0.77	0.20	1.29	64.4	45.78	30.30
19 Z	TD	4:1 WAG (10 CO2 Slugs) & Parallel Beds	37.24	18.59	2107	7.5	92.5	5.50	1.55	0.76	0.20	1.30	85.2	50.13	22.80
20 Z	TD	4:1 WAG (10 CO2 Slugs) & Parallel Beds	37.37	16.39	1101	11.3	88.8	5.50	1.55	0.77	0.20	1.25	63.9	58.99	30.30
21 Z	TD	4:1 WAG (10 CO2 Slugs) & High Perm Streak	38.69	15.84	1101	10.3	89.7	5.50	1.55	0.76	0.20	1.31	67.7	51.95	28.80
22 Z	TD	4:1 WAG (9 CO2 Slugs)	40.27	13.31	1101	7.1	92.9	2.50	1.29	0.96	0.10	0.66	36.9	62.65	25.70
23 Z	TD	4:1 WAG (10 CO2 Slugs)	41.16	17.36	1101	9.6	90.4	2.50	1.55	0.97	0.20	1.26	55.8	46.22	34.90
24 Z	TD	4:1 WAG (10 CO2 Slugs)	41.39	15.40	1233	8.9	91.1	5.50	1.55	0.76	0.20	1.42	68.5	98.17	28.20
25 Z	TD	4:1 WAG (10 CO2 Slugs)	40.81	8.18	1092	10.1	89.9	5.50	0.78	0.76	0.20	1.38	72.1	84.93	26.80

Table 4.1 (con't)

Summary of All Immiscible Carbon Dioxide Displacement Experiments

Comments			Model Parameters					Experimental Parameters					Results		
Run # — —	Model Type LC/TD —	Process Description	Average Porosity [ø] (%)	Abs Perm [k] (darcies)	Oil Visc [µ] (mPa•s)	Water Sat [Swc] (%)	Oil Sat [Soi] (%)	Run Press [p] (MPa)	Ave Flow Vel (m/d)	CO2 Required to Saturate (HCPV)	CO2 Vol Inj (HCPV)	CO2 Moles Inj (g-mol)	CO2 Required — (sm3/sm3)	CO2 Retained — (% inj)	Total Recovery [T-Rec] (% HCPV)
26aZ	TD	0.62 HCPV Waterflood (Tertiary)	40.40	11.22	1092	10.0	90.0	5.50	1.03	0.00	0.00	0.00	0.0	0.00	15.62
26bZ	TD	4:1 WAG (10 CO2 Slugs)	40.40	11.22	1092	24.1	75.9	5.50	1.03	0.76	0.20	1.37	68.5	90.34	18.55/21.98
27aZ	TD	1.20 HCPV Waterflood (Tertiary)	42.11	17.74	1092	10.3	89.7	5.50	1.55	0.00	0.00	0.00	0.0	0.00	21.78
27bZ	TD	4:1 WAG (10 CO2 Slugs)	42.11	17.74	1092	29.9	70.1	5.50	1.55	0.76	0.20	1.31	72.1	96.52	13.94/17.82
28 Z	TD	4:1 WAG (10 CO2 Slugs) & Sgi = 13.20% N2	39.03	11.65	1092	10.3	76.5	5.50	1.29	0.81	0.23	1.29	64.0	67.66	33.10
29 Z	TD	4:1 WAG (7 CO2 Slugs) & Sgi = 11.29% N2	42.72	16.67	1092	12.4	75.7	5.50	1.55	0.81	0.21	1.27	91.8	67.17	21.10
30 Z	TD	4:1 WAG (10 CO2 Slugs) & Sgi = 15.86% N2	40.53	16.61	1092	9.8	74.6	2.50	1.55	0.81	0.20	1.27	67.3	69.69	31.60
31 Z	TD	4:1 WAG (11 CO2 Slugs) & Sgi = 14.62% N2	41.08	13.32	1092	11.0	74.3	2.50	1.29	0.81	0.20	1.28	95.9	78.54	32.00
32 Z	TD	4:1 WAG (10 CO2 Slugs) & Sgi = 3.97% N2 (PB)	35.86	10.18	1092	8.5	87.5	2.50	1.03	0.77	0.20	1.26	61.5	87.53	32.20
33 Z	TD	4:1 WAG (10 CO2 Slugs) & Sgi = 15.29% N2 (HS)	37.59	18.94	1092	10.6	74.1	2.50	2.59	0.81	0.20	1.28	66.7	50.32	33.10
1 D	LC	1.92 HCPV Waterflood	35.00	11.10	1059	7.0	93.0	1.00	0.98	0.00	0.00	0.00	0.00	0.0	39.14
2 D	LC	1.44 HCPV Waterflood	35.00	5.58	1059	10.0	90.0	1.00	0.25	0.00	0.00	0.00	0.00	0.0	37.58
3 D	LC	4:1 WAG Process (10-Slugs)	36.60	10.66	1055	12.7	87.3	1.00	0.98	1.04	1.79	0.77	30.49	13.8	60.98
4 D	LC	4:1 WAG Process (10-Slugs)	36.30	11.54	1055	10.8	89.3	1.00	0.98	1.03	0.89	0.39	17.37	10.3	55.54
5 D	LC	4:1 WAG Process (5-Slugs)	35.63	10.81	1055	9.9	90.1	1.00	0.98	1.03	0.89	0.39	17.10	2.9	53.86
6 D	LC	4:1 WAG Process (1-Slug)	34.10	12.72	1055	10.8	89.2	1.00	0.98	1.03	0.89	0.39	24.85	6.0	46.37
7 D	LC	4:1 WAG Process (10-Slugs)	34.80	15.77	1055	9.4	90.6	1.00	0.98	1.03	0.20	0.09	4.44	8.4	46.97
8a D	LC	2.11 HCPV Waterflood (Tertiary)	37.05	11.38	1055	10.3	89.7	1.00	0.98	0.00	0.00	0.00	0.00	0.0	38.81
8b D	LC	4:1 WAG Process (10 CO2 Slugs)	37.05	11.38	1055	45.1	54.9	1.00	0.98	1.03	0.20	0.05	2.77	55.6	7.22/11.79
9 D	LC	4:1 WAG Process (10-Slugs)	36.73	12.67	1055	10.0	90.0	1.00	0.98	1.03	0.10	0.04	2.34	6.0	44.64
10 D	LC	4:1 WAG Process (10-Slugs)	35.77	10.98	1055	11.1	88.9	1.00	0.98	1.03	0.40	0.17	8.59	9.2	49.81
11 D	LC	8:1 WAG Process (10-Slugs)	38.28	14.00	1055	10.1	90.0	1.00	0.98	1.03	0.20	0.09	4.59	8.0	45.58
12 D	LC	2:1 WAG Process (10-Slugs)	38.40	16.15	1055	9.2	90.8	1.00	0.98	1.02	0.20	0.09	5.18	15.6	40.87
13 D	LC	4:1 WAG Process (10-Slugs) v/2	36.22	12.12	1055	9.5	90.5	1.00	0.49	1.02	0.20	0.09	4.63	53.31	44.92
14 D	LC	8:1 WAG Process (10-Slugs) v/2	36.93	12.05	1055	9.8	90.2	1.00	0.49	1.03	0.20	0.09	4.65	57.78	44.89
15 D	LC	2:1 WAG Process (10-Slugs) v/2	36.57	12.06	1055	9.7	90.3	1.00	0.49	1.03	0.20	0.09	4.74	23.51	43.97
16 D	LC	4:1 WAG Process (10-Slugs)	34.8	9.02	1059	20.9	79.1	2.50	0.98	1.02	0.64	0.75	29.71	93.91	52.73
17 D	LC	4:1 WAG Process (10-Slugs)	37.70	12.30	1055	10.8	89.2	2.50	0.98	0.97	0.20	0.26	12.6	20.46	48.02
18 D	LC	4:1 WAG Process (10-Slugs)	33.30	5.91	1059	10.3	89.7	5.50	0.98	0.76	0.21	0.74	43.4	100.00	46.81

Table 4.1 (con't)

Summary of All Immiscible Carbon Dioxide Displacement Experiments

Comments			Model Parameters					Experimental Parameters					Results		
Run # — —	Model Type LC/TD —	Process Description	Average Porosity [ø] (%)	Abs Perm [k] (darcies)	Oil Visc [µ] (mPa•s)	Water Sat [Swc] (%)	Oil Sat [Soi] (%)	Run Press [p] (MPa)	Ave Flow Vel (m/d)	CO2 Required to Saturate (HCPV)	CO2 Vol Inj (HCPV)	CO2 Moles Inj (g-mol)	CO2 Required — (sm3/sm3)	CO2 Retained — (% inj)	Total Recovery [T-Rec] (% HCPV)
19 D	LC	4:1 WAG Process (10-Slugs)	34.40	12.36	1059	10.8	89.2	5.50	0.98	0.76	0.20	0.70	44.8	98.90	42.88
20 D	LC	4:1 WAG Process (10-Slugs)	35.77	12.45	1055	10.7	89.3	5.50	0.98	0.76	0.20	0.78	37.8	80.04	49.07
21 D	LC	4:1 WAG Process (10-Slugs)	36.69	15.09	1055	6.1	94.0	5.50	0.98	0.75	0.10	0.42	18.9	68.21	49.02
22 D	LC	4:1 WAG Process, Wainwright	36.67	11.41	150	11.8	88.2	1.00	0.98	0.69 #	0.20	0.09	3.4	6.07	64.96
23aD	LC	2.29 HCPV Waterflood, Wainwright (Tertiary)	36.22	11.46	150	13.0	87.1	1.00	0.98	0.00	0.00	0.00	0.0	0.00	60.71
23bD	LC	4:1 WAG (10 CO2 Slugs), Wainwright	36.22	11.46	150	65.8	34.2	1.00	0.98	0.70 #	0.20	0.05	1.2	12.52	5.01/12.4
# 1D	TD	4:1 WAG (10 CO2 Slugs) Senlac	43.10	7.62	3295	13.2	86.8	2.50	0.78	0.99	0.61	1.41	45.4	48.91	40.86
# 2D	TD	4:1 WAG (10 CO2 Slugs) Senlac	41.50	7.41	3295	9.9	90.1	4.10	0.78	0.85	0.33	1.41	40.2	28.68	46.26
# 3D	TD	4:1 WAG (10 CO2 Slugs) Aberfeldy	40.59	13.31	1055	8.7	91.3	1.00	0.83	1.02	0.20	0.16	4.8	65.99	43.30

Abbreviations and Symbols

Tank Sand = Cleaned Aberfeldy Tank Sand
Continuous CO2 => WF : A Single CO2 Slug Followed by a Waterflood
High Perm Streak (HS) : Diagonal Bed of High Permeability Glass Beads
Parallel Beds (PB) : Layer of Sand and a Layer of Glass Beads

WF = Waterflood
CO2 = Carbon Dioxide Gas
N2 = Nitrogen Gas
Sgi = Initial N2 Gas Saturation

* : Refers to Nitrogen Rather than Carbon Dioxide
? : Value is Highly Questionable due to Equipment Problems

CO2 Required = Total CO2 Injected (std. cond.) / Total Oil Produced
CO2 Retained = Percentage of Total CO2 Injected & Not Produced
Total Recovery = Process Recovery + Waterflood Recovery + Blowdown Recovery

" R " : Gonzalo Rojas (1983 - 1985)
" Z " : Tao Zhu (1985 - 1987)
" D " : Steve Dyer (1987 - 1989)

T-REC: HCPV Basis/RHCPV Basis & RHCPV = oil remaining after WF

Aberfeldy Solubility:	Rso (sm3/m3)	Rsw (sm3/m3)
@ 1.00 MPa	10.14	4.97
@ 2.50 MPa	26.86	10.74
@ 5.50 MPa	68.51	19.91

HCPV Required to Saturate= { Rso + [Rsw x (1/Soi - 1)] } x 0.096089
HCPV Required to Saturate= { Rso + [Rsw x (1/Soi - 1)] } x 0.034584
HCPV Required to Saturate= { Rso + [Rsw x (1/Soi - 1)] } x 0.010791

breakthrough occurred very early, upon the injection of <1% HCPV showing the dominance of viscous forces, and relatively small effect of mass transfer between carbon dioxide and oil. Recovery was about 3% at the end of slug injection when the gas-oil ratio was of the order of 1000 sm^3/sm^3. The total recovery varies considerably due to the differences in injection rates as well as unstable displacement. On the whole, recovery was enhanced with a decrease in the injection rate of carbon dioxide and increase in the injection rate of water.

Carbon Dioxide WAG Process

A more efficient mode of carbon dioxide injection is to split the slug into several slugs (10 for most runs) and to alternate the smaller gas slugs with water. The overall volume (at model conditions) of water-to-carbon dioxide slug size is termed the WAG ratio. After the desired volume of carbon dioxide has been injected, water is injected continuously until the instantaneous producing water-oil ratio exceeds 20:1. This process was employed for the majority of runs. The WAG ratio was varied from 1:1 to 6:1. The 4:1 WAG was ratio found to be the optimum.

Table 4.1 shows that the incremental oil recovery (over a waterflood) by the WAG process ranged approximately from 6 to 15 percentiles HCPV. The WAG ratio also had considerable effect on the cumulative water-oil and gas-oil ratios. Both of these tended to decrease with an increase in the WAG ratio up tc about 4:1. The carbon dioxide requirement also tends to be small for this WAG ratio.

Carbon Dioxide Slug Size

In Runs 14Z and 17Z, 40 and 10% HCPV slugs of carbon dioxide were employed. The 40% slug yielded a recovery of only 0.7 percentiles greater than the 20% slug, suggesting that 20% was optimal. The gas-oil ratio in the case of the 40% slug was much higher, pointing to inefficient carbon dioxide utilization. Recovery was 35.4% for the 10% slug, yet the gas-oil ratio was higher than that for the 20% slug.

Nitrogen WAG Floods

Runs 4Z through 8Z were similar to other WAG runs, except that nitrogen was employed in place of carbon dioxide. The slug size was 20% HCPV, and the WAG ratio was 4:1. Table 4.1 gives the relevant data. In all runs, nitrogen breakthrough occurred almost immediately upon injection. Water breakthrough occurred at approximately 0.20 PV injection, except in Run 8Z, where the water was initially mobile. Recoveries for Runs 4Z through 7Z were 33.0, 32.4, 31.6, and 32.7%, respectively. The waterflood recovery averaged 29%. Further, the blowdown recoveries for the same runs were: 4.1, 3.0, 2.4, and 2.6%, respectively. Thus it is evident that the oil recovery in the nitrogen runs was essentially the waterflood recovery plus blowdown recovery, attributable to gas compressibility. Run 8Z, with an initial waterflood residual oil saturation, gave a total recovery of 31.6%, although the waterflood recovery in this case was lower. However, this was compensated by the subsequent gas drive effects. Based upon the above results, it can be concluded that the use of a noncondensable gas, such as nitrogen, in place of carbon dioxide essentially does not lead to incremental oil recovery. In Run 15Z, a 10% carbon dioxide slug was followed by a 10% nitrogen slug, which was driven by water. The recovery in this case was 35.4%, which is identical to the recovery obtained in Run 17Z, employing a 10% carbon dioxide slug. The oil recovery in the case of the composite slug (carbon dioxide was injected first) was delayed by about 0.20 PV.

Effect of Operating Pressure

In most runs conducted, the operating pressure was held constant at 5.5 MPa. Runs 22Z and 23Z employed an operating pressure of 2.5 MPa to examine the effect of pressure. The carbon dioxide slug size in these runs was 10 and 20% HCPV, respectively (equivalent to those at 5.5 MPa, in terms of total number of moles). The oil recoveries from these runs were 25.7 and 34.9%, respectively, and can be compared to the recoveries of 35.4 and 43.0%, for similar high pressure runs, Runs 17Z and 16Z, respectively. There was a considerable drop in oil recovery in the case of the 10% slug, but the recovery was approximately eight percentiles lower in the case of the 20% slug. It is believed that the larger amount of carbon dioxide at the higher pressure is inefficiently utilized, as also reflected by the higher producing gas-oil ratios.

Effect of Initial Gas Saturation

In Runs 9Z to 11Z and 28Z to 33Z, the porous medium contained an initial gas saturation (nitrogen in 9Z and 28Z to 33Z, carbon dioxide in 10Z and 11Z). In Runs 30Z to 33Z, the operating pressure was 2.5 MPa, while in the other runs it was 5.5 MPa. Two types of heterogeneous packs were employed to examine the combined effects of pressure and heterogeneities. In all of these runs, oil production was delayed due to the presence of an initial noncondensable free gas phase. This effect was more pronounced at the higher pressure. When the gas phase was mobile (Sgi > 5% PV), only gas was produced initially. Subsequently, all gas production ceased, and only an emulsion of oil and water was produced. Comparing the results of these runs with those of Runs 24Z and 25Z, where there was no initial gas saturation, it can be seen that the recovery was only slightly better when a gas phase was present. In any event, the overall performance deteriorated due to a gas saturation. In Runs 9Z to 11Z, the oil recovery was higher in the case of a carbon dioxide preflush, due to oil viscosity reduction, as compared to nitrogen.

Effect of Heterogeneities

Several runs were carried out to examine the effect of two types of porous pack heterogeneities on the process efficiency. The carbon dioxide slug size and the WAG ratio were held constant at 20% HCPV and 4:1, respectively. The runs were repeated for two oils. Other data for the runs (18Z to 21Z) is given in Table 4.1.

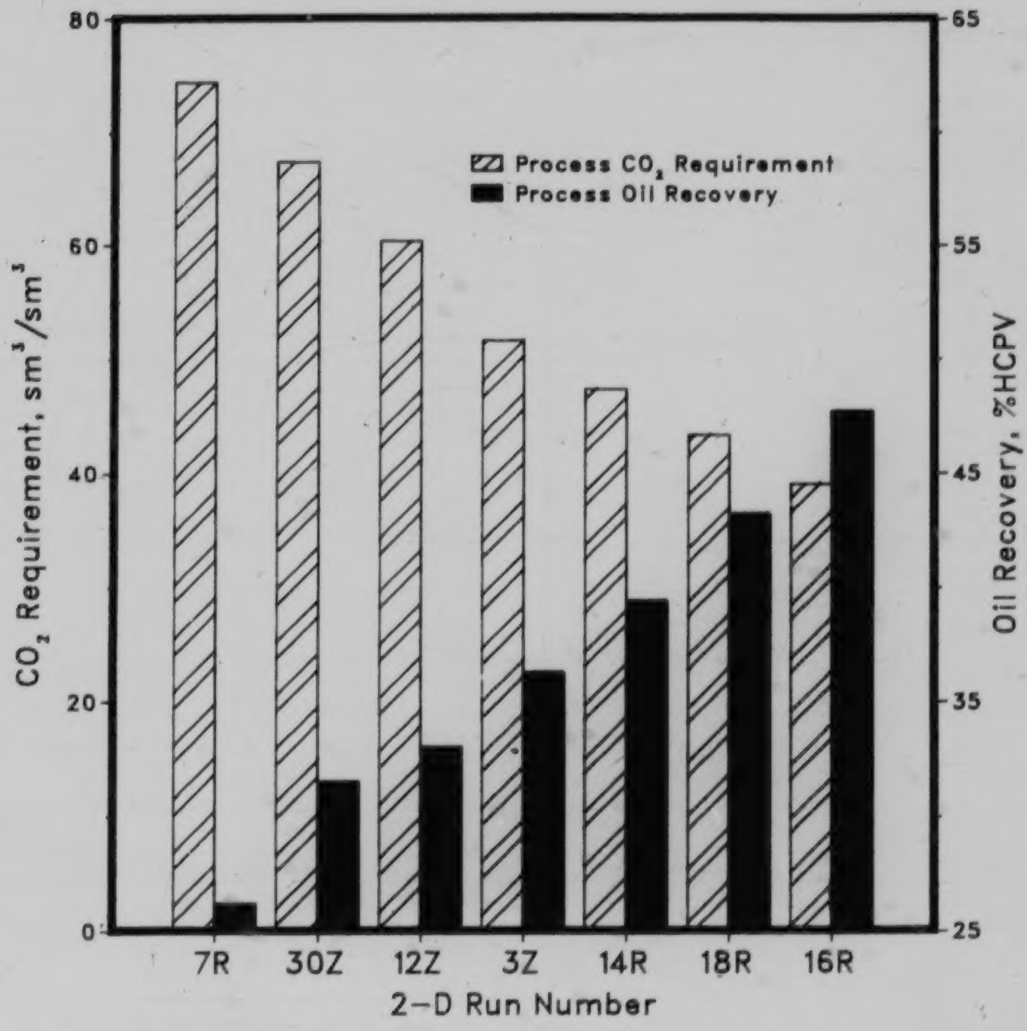
Runs 18Z and 21Z employed the model with a high permeability channel packed along the diagonal connecting the injection and production wells. The permeability of the channel was 25 darcies, compared to the pack permeability of 17 darcies. The oil recovery for Run 18Z was 30.3% for the more viscous oil, while it was 28.8% in Run 21Z for the less viscous oil. This somewhat unexpected performance may be attributed to the nonuniformity of the packs. This can be compared to the recovery of 43% for a uniform pack in Run 16Z. In the heterogeneous packs, carbon dioxide breakthrough occurred earlier and the gas-oil-ratio was much higher.

In Runs 19Z and 20Z, the model was packed with two communicating, parallel equal thickness layers, with permeabilities of 25 and 10 darcies, respectively. Run 20Z, utilizing the less viscous oil, yielded a recovery of 30.3%, while Run 19Z, employing the more viscous oil, gave a recovery of 22.8%. It is evident that these values are considerably below those for a uniform pack, due to inefficient utilization of carbon dioxide. At the same time, the drop in oil recovery is not as drastic for the immiscible carbon dioxide process as would be expected for a gas-based process.

Overall Process Evaluation

Figure 4.1 summarizes selected results for oil recovery and carbon dioxide requirement for the two-dimensional model runs. Figure 4.1 illustrates the trend of increasing oil recovery while carbon dioxide requirements are reduced. The optimum process shown is Run 16R where the oil recovery is highest and carbon dioxide requirement is lowest.

The highest recovery for all of the previous experiments was 61.2 % in Run 11Z, where a carbon dioxide preflush was used prior to the WAG process. The carbon dioxide requirement for Run 11Z was 758.9 sm^3/sm^3: clearly a very inefficient use of carbon dioxide. The lowest recovery was obtained in Run 22Z, which utilized a 10% HCPV carbon dioxide slug at the lower pressure of 2.5 MPa. The lowest carbon dioxide requirement was 28 sm^3/sm^3 (Run 17Z) for a 10% slug.



7R: 1 CO_2 Slug => 0.66 HCPV Waterflood, Tertiary

30Z: 4:1 WAG & 15.86% N_2 Gas Saturation

12Z: Single CO_2 Slug => 2.48 HCPV Waterflood

3Z: 1.77 HCPV Waterflood => 4:1 WAG, Tertiary

14R: 1:1 WAG [10–CO_2 Slugs]

18R: 6:1 WAG [10–CO_2 Slugs]

16R: 4:1 WAG [10–CO_2 Slugs]

[5.50 MPa & 23°C, 1032 mPa.s Oil & 0.20 HCPV CO_2 Injected]

Figure 4.1 – Process Vs. Recovery & CO_2 Requirement Two–Dimensional Model.

Based upon the preceding investigations the following conclusions were reached. The immiscible carbon dioxide flooding process can yield as much as 15% incremental oil, over a waterflood, in the case of moderately viscous oils, at carbon dioxide requirements below 100 sm3/sm3. Substitution of nitrogen yielded nearly the same recovery as a waterflood; therefore it is concluded that the mechanisms postulated for carbon dioxide are probably valid.

Oil recovery appeared to reach a plateau for a 20% HCPV total slug of carbon dioxide. Among the WAG ratios tested, the 4:1 ratio seemed optimal for both high and low initial oil saturations. Oil recovery was found to be sensitive to the operating pressure, decreasing with a reduction in pressure, and to formation heterogeneities. The drop in oil recovery was not large in either case. An initial gas saturation may lead to a small decrease in oil recovery. A mobile gas phase had an adverse effect on performance.

Chapter V

Experimental Apparatus and Procedures

The following chapter provides a description of the apparatus, materials, and procedures used for the present research. The majority of the experiments were conducted using the partially scaled linear model, while several runs were carried out on the two-dimensional model. Appendix E gives detailed information pertaining to the laboratory apparatus and procedures.

Experimental Apparatus

The apparatus used in this study is comprised of the following major components: physical model, fluids and porous medium, fluid injection and production systems, and the data acquisition system. Figure 5.1 gives a schematic illustration of the apparatus used for these physical model studies. Plate 5.1 provides an overview of the experimental apparatus. Plate 5.2 shows a close-up of the linear core model with the two-dimensional model in the background.

Physical Models

Two models were used in the in the present investigation. A partially scaled linear core model was constructed for this study. This model was used for the majority of experiments conducted in this investigation. A fully scaled physical model designed by Rojas[22], was constructed and built in 1983. This model was used in the investigation of the Lloydminster Senlac reservoir.

Linear Core Model

The linear core model was built for three main purposes.

1. To act as a screening model for the larger, more time consuming two-dimensional model.
2. To isolate the displacement and mobilization efficiencies by assuming vertical and areal sweep to be equal to unity in the linear core model.

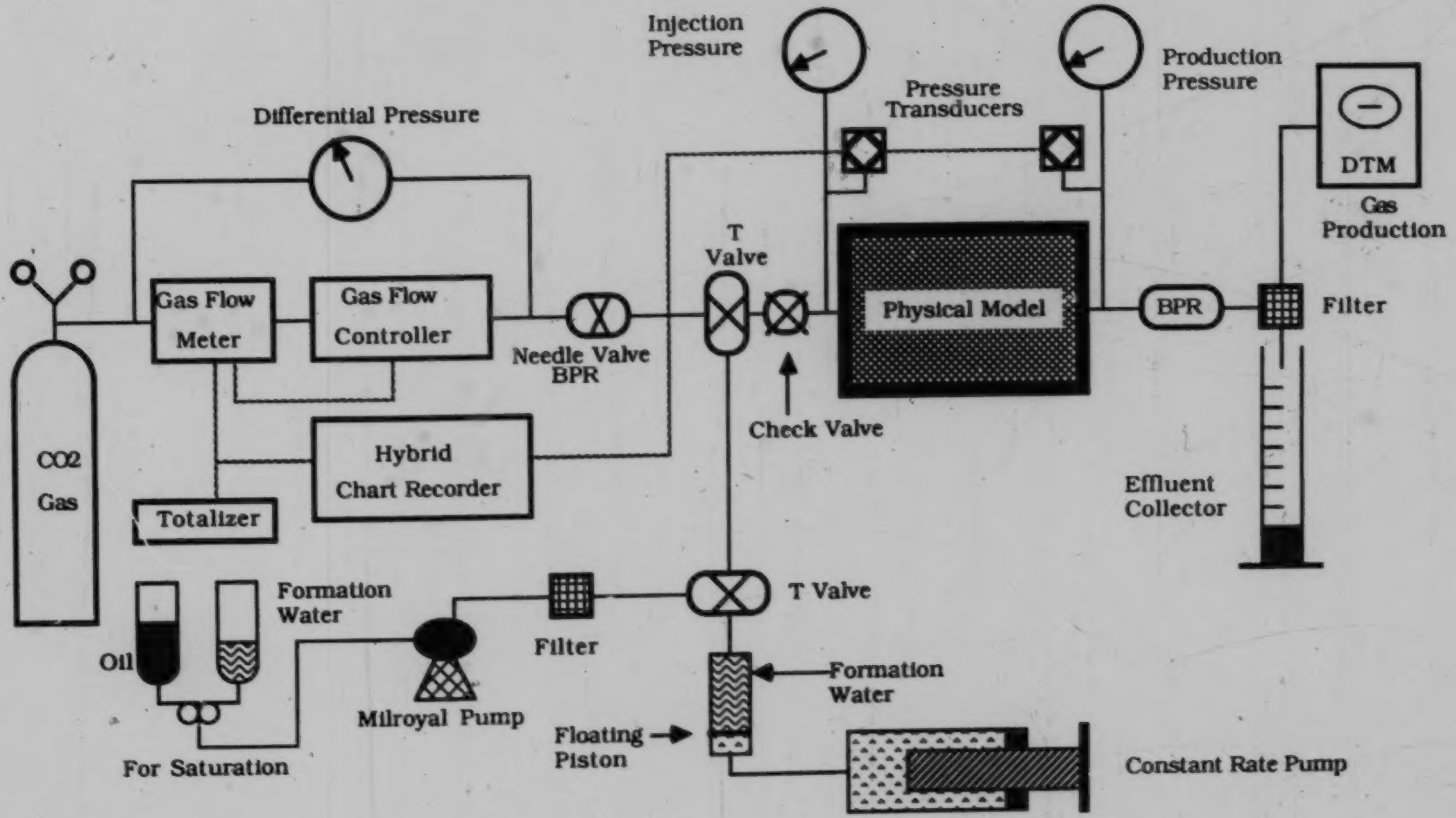

Injection Pressure
Production Pressure
Pressure Transducers
Differential Pressure
DTM
Gas Production
T Valve
Gas Flow Meter
Gas Flow Controller
Needle Valve BPR
Physical Model
BPR
Filter
Check Valve
CO2 Gas
Hybrid Chart Recorder
Totalizer
Effluent Collector
T Valve
Formation Water
Oil
Filter
Milroyal Pump
Formation Water
Floating Piston
For Saturation
Constant Rate Pump

Figure 5.1 - Schematic of the Physical Model Apparatus.

3. To simulate the direct line drive flooding pattern.

The geometric scaling factors for the two-dimensional model were modified to fit a circular cross-sectional area. The geometric scaling criterion for the two-dimensional model is as follows:

$$\frac{(L / H)_m}{(L / H)_p} = \frac{(L / W)_m}{(L / W)_p} = 1 \qquad (5.1)$$

The cross-sectional area of the field was assumed to be rectangular and of dimensions H • W. This rectangular cross-section was related to an equivalent diameter as follows:

$$H \bullet W = \frac{\pi}{4} D^2 \qquad (5.2)$$

$$\therefore \quad D = 2 \sqrt{\frac{(H \bullet W)}{\pi}} \qquad (5.3)$$

The modified geometric scaling factor is now as follows:

$$\frac{(L / D)_m}{(L / D)_p} = 1 \qquad (5.4)$$

where subscripts,

m = model
p = prototype

The model presently being used is 415 mm in length and 98 mm in diameter. A Chevron-type fitting was used to seal the ends of the pipe as well as forming the injection and production ports. This system of sealing the end of a core, rather than the conventional flanged method was implemented due to availability of material. It was also felt that this system would more closely realize our assumption of perfect areal and vertical sweep efficiency.

Two-Dimensional Model

Extensive information pertaining to the scaling, design, construction, and operation of the two-dimensional model is available,

Plate 5.1 - Overall View of the Physical Model Apparatus.

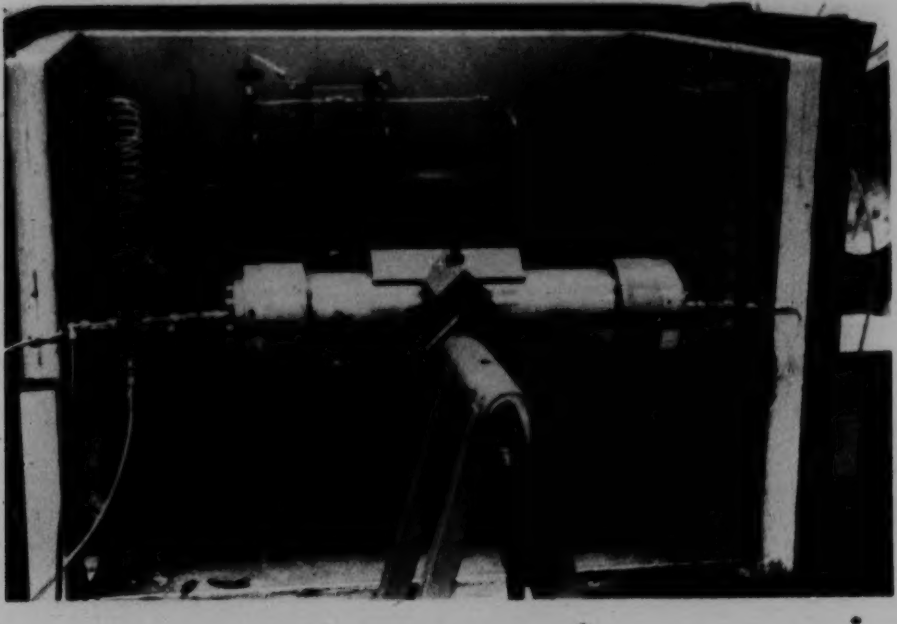


Plate 5.2 - Close-Up of the Linear Core Model.

in detail, from theses[15,22] published at the University of Alberta. This information will not be given in this work.

Fluids and Porous Medium

Table 5.1 is a summary of the prototype reservoir property data used in this investigation. The prototypes considered were shallow, thin, horizontal, unconsolidated sandstone reservoirs with rock and fluid properties similar to the average properties of the Lloydminster area.

Fluids

Commercial grade carbon dioxide (99.5% purity) was used in all of the displacement experiments. Each run also employed formation water (brine) to create an irreducible water saturation. Crude oil from the Aberfeldy field was mixed with a conventional light oil (198 mPa•s) to achieve the desired viscosity. The crude oil from the Senlac field was as received. For both crude oils it was necessary to dehydrate the oil before use. Appendix E gives a detailed analysis of the dehydration and mixing procedures of the oils to attain the desired characteristics.

Porous Medium

The sand used in this investigation was Ottawa Silica Sand, from Ottawa Michigan. Table 5.2 shows the bulk mineralogy of the sand determined by x-ray analysis. Quartz comprises the bulk mineralogy. Studies conducted by Rojas[22] showed that the Ottawa Silica Sand showed a similar particle size distribution with core samples taken from the Aberfeldy field but with smaller amounts of fines (see Figure 5.2).

Fluid Injection and Production Systems

A new gas injection system had to be developed for the injection of carbon dioxide gas at low pressures. The previous system, of a constant rate injection pump, relied on the carbon dioxide behaving

Table 5.1
Reservoir Property Data

Pool :	Aberfeldy	Senlac
Year Discovered :	1957	1980
Producing Horizon :	Lloydminster sand	Lloydminster sand
Producing System :	Cretaceous	Cretaceous
Well :	various	16-35-38-27 W3M
Perforation Interval [m] :	500 - 600	788 - 791
Net Pay [m] :	6.1	4.8
Porosity [%] :	35.0	27.7
Permeability [darcies] :	1 - 3	2.5
Water Saturation [%] :	13.0	30.0
Oil Saturation [%] :	87.0	70.0
Reservoir Temperature [°C] :	21.0 - 22.0	27.8
Reservoir Pressure [MPa] :	3.45	2.5 - 4.1
Oil Gravity [°API] :	15 - 17	14.6
Oil Viscosity [mPa•s] :	1000 - 5000	1000 - 3500
Reservoir Water		
Density @ 23 °C [kg/m3] :	1047.0	1025
Viscosity @ 23 °C [mPa•s] :	1.14	1.11
Refractive Index @ 23 °C :	1.3427	1.3405
pH @ 23 °C :	7.5 - 8.1	7.42
Total Solids [mg/l] :	76,190	41,200
Hardness [mg/l] :	8757	1500
Sulphates [mg/l] :	39,477	25
Alkalinity [mg/l] :	57.6	—

Table 5.1 (cont.)

Reservoir Property Data

Pool :	Abertfeldy	Senlac
Sodium [mg/l] :	15,727	15,670
Calcium [mg/l] :	105	220
Magnesium [mg/l] :	658	230
Iron [mg/l] :	3.17	0.82
Manganese [mg/l] :	3.4	0.37
Potassium [mg/l] :	271	230
Silicon [mg/l] :	7.65	—
Aluminum [mg/l] :	4.46	—
Salt [mg/l] :	66,069	24,370

Note: Senlac data obtained from Dr. S. Huang, the Saskatchewan Research Council
Aberfeldy data obtained from Dr. Karl Miller, Husky Oil Operations Ltd, Calgary

Table 5.2

Bulk Mineralogy of Ottawa Silica and Lloydminster Aberfeldy Tank Sand[†]

Sand Sample	Quartz	Orthoclase	Clays	Type of Clay
Ottawa Silica	M	--	t	Possibly Illicite/Smectite
Lloydminster Aberfeldy	M	mt	mt	Kaolin Group Mineral and Possibly Chlorite and Illite

M = major component

mt = minor to trace $\quad$ M > mt > t

t = trace

† Determined by the Department of Geology, University of Alberta

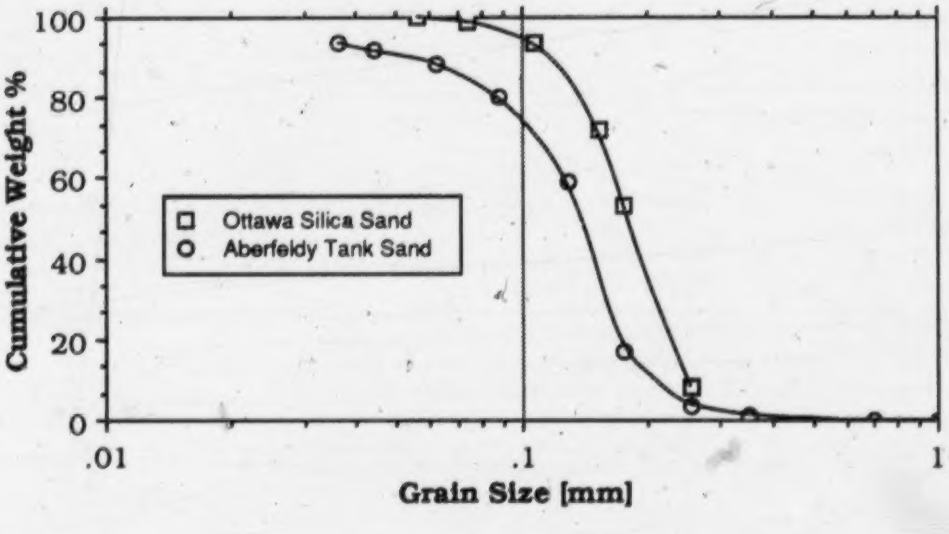


Figure 5.2 - Particle Size Distribution of Ottawa Silica and Aberfeldy Tank Sand.

similarly to a liquid at elevated pressures and room temperature for accurate volume determination.

Fluid Injection

For low pressure carbon dioxide gas injection a Matheson gas system was implemented. This system controls and measures the mass flow rate of carbon dioxide. The tank pressure acts as the driving force and a Matheson Modular Dyna-Blender controls and measures the mass flow rate of carbon dioxide. A digital readout and a Hybrid chart recorder track the volumetric flow rate at meter conditions (101.325 kPa & 21.1°C). A Matheson Totalizer provides the cumulative volume of the gas injected. Plate 5.3 gives an overall view of the injection apparatus. Due to the sensitivity of the aforementioned equipment, several additional features were added for the precise measurement and control of the injected gas. The most notable of these was the addition of a pressure differential gauge across the Matheson flow meter and flow controller. These two pieces of equipment were specified to give accurate results when operated under a pressure differential of 35 kPa or less. To achieve this, a micrometer type needle valve was placed downstream of the control devices to act as an extremely sensitive back pressure regulator.

A constant rate, screw-type, high pressure piston pump was used to inject the brine at a constant rate into the porous medium. The injection rate was controlled by varying the pump speed. Due to the corrosive nature of the brine (high salinity), it was injected into the model from a high pressure steel cylinder with a floating piston which was actuated by the constant rate pump.

Fluid Production

The effluents from the model were separated in a glass separator operating at room conditions. The top of the separator was connected to a dry test meter (DTM) to measure the volume of gas produced at room conditions (92.86 kPa and 23°C). Liquids (oil, water, emulsion) were collected in graduated cylinders from the bottom of the

Plate 5.3 - Overall View of the Injection Apparatus.

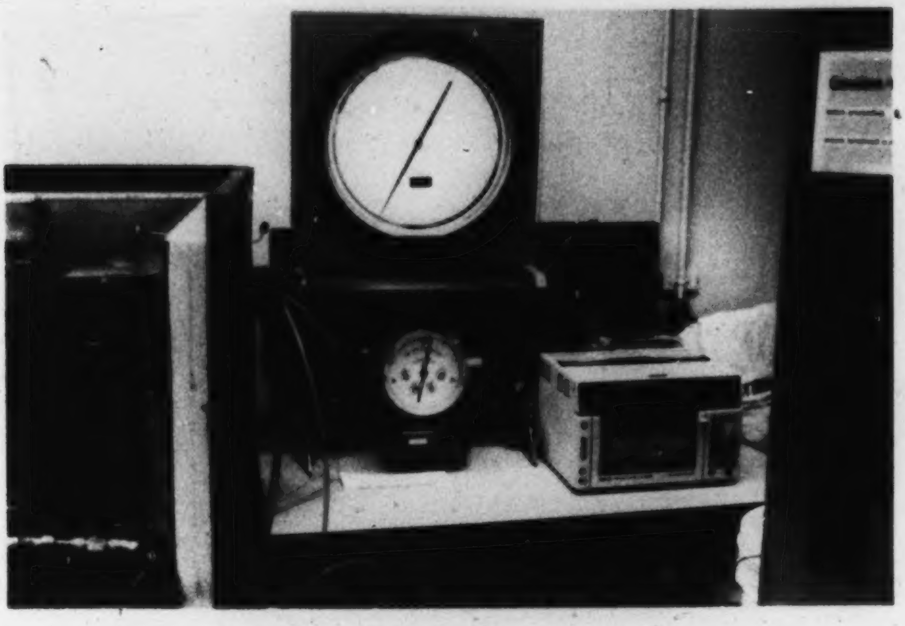


Plate 5.4 - Overall View of the Production Apparatus.

separator. Plate 5.4 gives an overall view of the production apparatus. All valves, fittings, and connections were constructed of 3 or 5 mm stainless steel to prevent corrosion and to exercise precise control of the production and injection fluid volumes. Appendix E gives precise details on all of the apparatus used in this investigation.

Data Acquisition System

The production pressure was controlled by a back pressure regulator (BPR) which was located immediately between the physical model and the separator. Two 20 MPa Heise pressure gauges were used to measure the injection and production pressures. Although only 1/20th of the full scale of the gauge was used for most runs, they were calibrated and deemed accurate to within ± 5%. A Hybrid chart recorder was used to monitor and record the injection and production pressures, model temperature, and the gas injection rate. The Hybrid recorder was invaluable in its use for keeping the gas injection rate constant as this system relied upon a slight pressure differential across the system. The cumulative volume of gas produced was measured with a dry test meter (DTM) with an accuracy of 10 cm^3 at room conditions.

Experimental Procedures

A detailed description of the experimental procedures is presented in Appendix E. Some of the major headings in Appendix E are: oil preparation, bulk and pore volume determination, permeability determination, saturation procedures, experimental calculations and procedures, cleanup, etc. This appendix is now being used as a manual for all future investigators working on the immiscible carbon dioxide project at the University of Alberta. It was preferentially written in terms of the linear core model because it was the latest model to be used. The procedures are very similar for the two-dimensional model and these similarities are documented throughout. Under the major headings throughout Appendix E, there are several remarks describing the general process which will occur during the sequence of steps.

Chapter VI

Presentation and Discussion of Results

The following chapter is divided into two sections. The first section describes the presentation of results in tabulated and graphical forms. The second section is a discussion of the results obtained during this investigation.

Presentation of Results

Experimental data for each run was collected by recording all pertinent information on individual run forms. Effluent measurements were recorded after each alternating slug in an effort to analyze the relative efficiency of each WAG slug. All results are presented in metric units with the exception of permeability, which is given as darcies (1 μm^2 = 1.01325 darcies).

Processing of Data

Appendix D contains all the programs used in the processing and preparation for presentation of results for each run. The following seven values were entered into a data file for each effluent analysis: injection pressure, production pressure, volume of gas injected, volume of water injected, volume of oil produced, volume of water produced, and the volume of gas produced. The tables generated for each experiment list all the pertinent data recorded from each run. From this information a material balance on oil, water, and carbon dioxide was executed. From the material balance calculations, the following values were obtained and tabulated (Appendix A): carbon dioxide requirement, carbon dioxide retention, instantaneous ratio of volume of fluid injected-to-the pore volume [VFI/PV], cumulative volume of oil produced, percent oil recovery [%Rec], producing water-oil ratio [WOR], producing gas-oil ratio [GOR], and instantaneous oil-produced:fluid-injected ratio [OPFIR]. The data from the table was then used to generate a series of descriptive plots, which were analyzed to determine what occurred in the model during the experiment and the effectiveness of the recovery process tested.

Carbon dioxide requirement is a parameter used in assessing the economics of the process. Carbon dioxide requirement is the ratio of total carbon dioxide injected (sm^3) to the total volume of oil produced (sm^3).

Carbon dioxide retention is the percentage of the carbon dioxide injected that was not produced during the experiment. Produced gas includes that which was produced during all three phases of the process. Carbon dioxide retention indicates the percentage of the total volume of carbon dioxide injected that reacts with the oil and water. Retention of carbon dioxide, after the blowdown phase, is due to carbon dioxide that either remains dissolved in the oil [$R_{so} \leq 1.0$ sm^3/sm^3 at room conditions] or as a free gas phase.

Total oil recovery is the sum of the recovery components: WAG process, post-waterflood, and blowdown. The WAG process consists of injecting alternate slugs of carbon dioxide and water until the desired amount of carbon dioxide is injected. The post-waterflood phase is initiated after the WAG process and terminated at a producing water-oil ratio greater than 20:1. The blowdown recovery is the oil recovered, after termination of the flood, by depleting the pressure in the model to room conditions.

For the tertiary experiments, total recovery is reported as both residual oil recovery (%RHCPV) based on the recovery of oil remaining in the model after initially waterflooding to a producing water-oil ratio of 20:1, and total recovery which includes the oil produced during the initial waterflood (%HCPV). Note that in some runs the post-waterflood phase was not initiated. This was due to the fact that the producing water-oil ratio reached or exceeded the artificial economic limit (20:1 WOR) during the WAG process.

Presentation of Data

For each run conducted several plots are generated from the raw tabulated data given in Appendix A. These figures graphically illustrate the changes occurring in the model during the process in order to provide an understanding of the mechanisms of displacement.

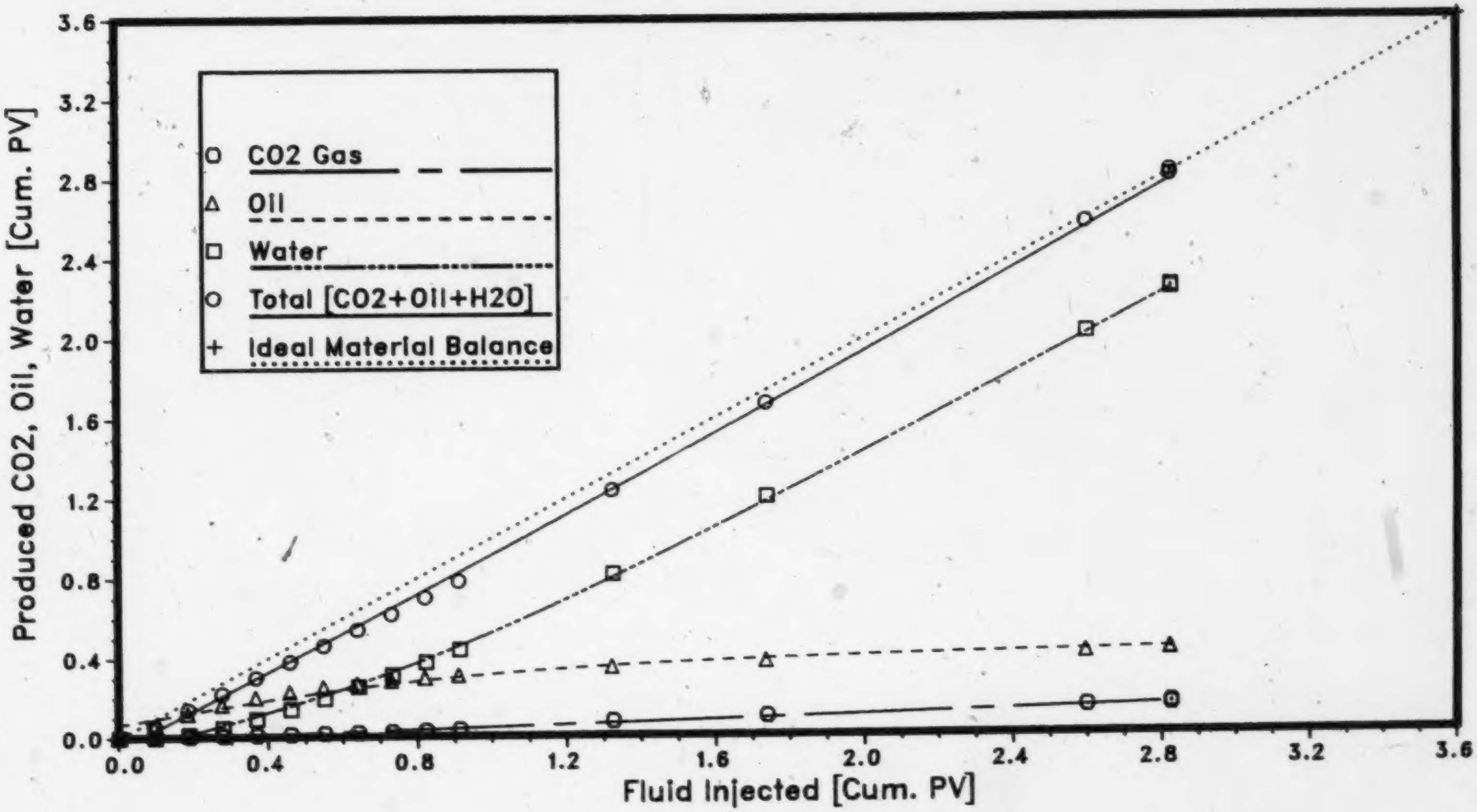
At the bottom of each of the aforementioned figures there is a detailed description of all the variables involved in the experiment as well as a descriptive title. This information was included so that any figure may be taken from the context of the thesis and retain its unique identity.

Volumetric Balance

Appendix B gives the figures depicting the volumetric balance on oil, water, and carbon dioxide to check for experimental errors in measurement. The three phases are combined and plotted as the Total [CO_2+Oil+H_2O]. This curve is then compared with an ideal material balance line (see Figure 6.1). The difference between the "Total" curve and the "Ideal" curve is a measure of experimental error. The major part of the error for most runs was in the measurement of the produced carbon dioxide gas. The vertical portion of the curves at the endpoints is the blowdown recovery associated with each phase, viz. production of effluent with no injection.

Production History

Appendix C gives the figures depicting the production history plots showing producing water-oil ratio (WOR), producing gas-oil ratio (GOR), cumulative total oil recovery (RECOVERY), and instantaneous oil-produced:fluid-injected ratio (OPFIR), all versus cumulative pore volumes of fluid injected. It is important to note the x-axis scale differences between runs. Figure 6.2 shows a sample plot. For example, in Run LC3 (Figure C.3) the x-axis scale is 0.0 to 9.0 cumulative PV of fluid injected, while for Run LC9 (Figure C.9) the x-axis scale is 0.0 to 2.8 cumulative PV fluid injected. This is important



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 34.80 %, k = 15.774 darcies, S_o = 90.58 %, S_{wc} = 9.42 %

[0.20 HCPV CO2 @ 1.00 MPa (0.08 g–mol) 4:1 WAG, 10–Slugs]

Figure 6.1 – Volumetric Balance on Run LC 7.

because it shows how the carbon dioxide process may drastically alter the life of a flood.

The shapes of the gas-oil ratio and water-oil ratio curves are extremely dependent on the frequency of effluent analysis. In most cases the effluent is analyzed after each slug (CO_2 or water) has been injected during the WAG process, and much less frequently during the post-waterflood stage.

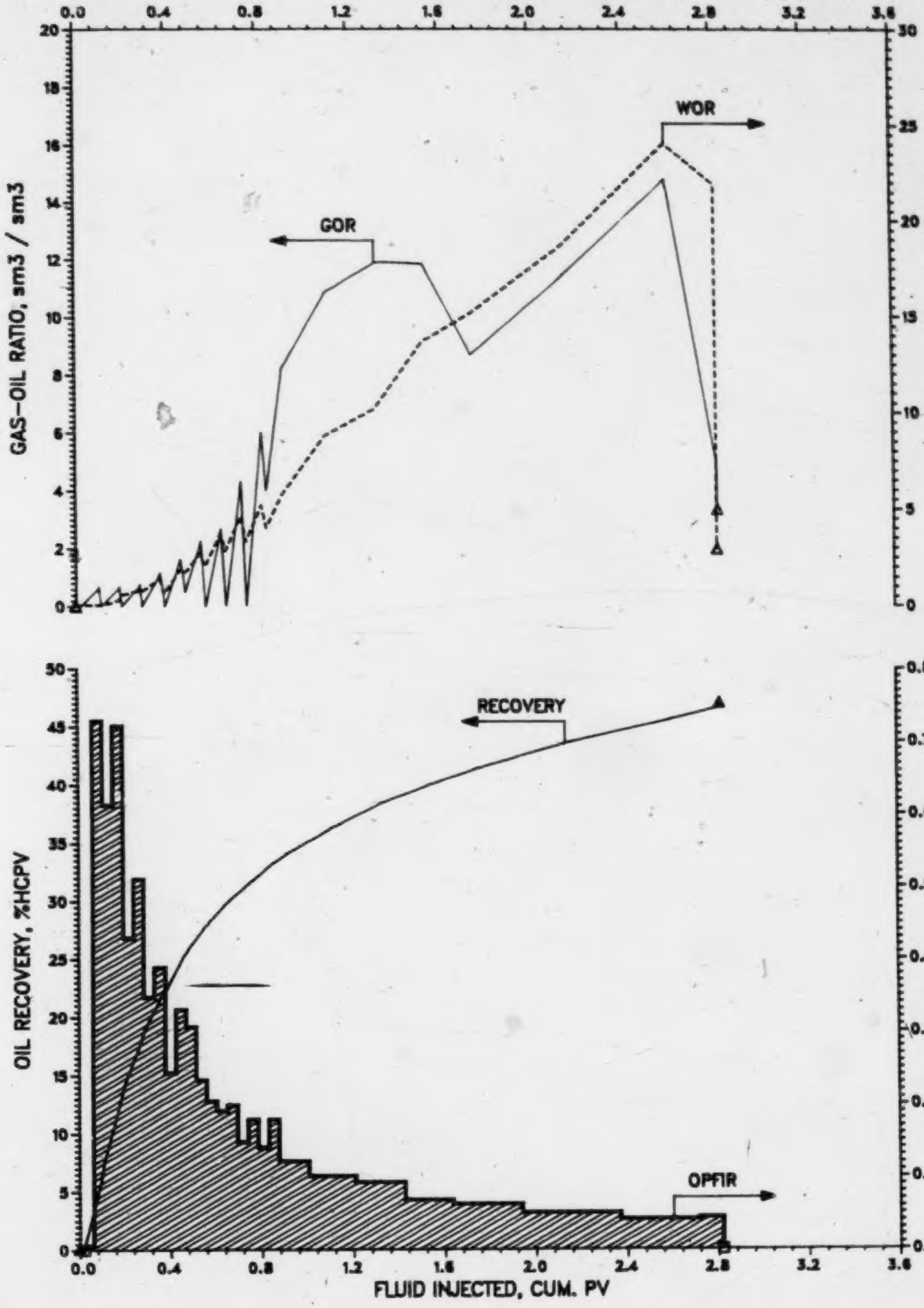
For most runs the gas-oil ratio curve exhibits rapid fluctuations during the early stages of the experiment (see Figure 6.2). The appearance of produced gas, almost immediately after injection, is attributed to the extremely adverse viscosity ratio between carbon dioxide gas and heavy oil. It was discovered that the dry test meter (DTM), used for measuring the volume of produced gas, gave a spurious reading of gas production during the early stages of the experiment. This would indicate that carbon dioxide breakthrough is delayed somewhat greater than is illustrated in the plots.

The instantaneous oil-produced:fluid-injected ratio (OPFIR) curve reflects the mobilization efficiency of the process. This curve represents the relative oil production rates, if one considers that the fluid injected will have approximately the same incremental volume. For most runs, the dominant portion of the displacement occurred during the early portion of the WAG process.

Slug Recovery Distribution

The slug recovery distribution (see Figure 6.7) illustrates the sequence of oil recovery, during various injection stages, as well as the fractional recovery for the entire process. The purpose of these new figures is to analyze the relative efficiency of each slug during the WAG process. The plot is divided into two parts, a pie chart and a bar chart.

The pie chart shows the fractional recovery of oil during the various phases involved in any one experiment. As well, it shows the



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 34.80 %, k = 15.774 darcies, S_o = 90.58 %, S_{wc} = 9.42 %

[0.20 HCPV CO2 @ 1.00 MPa (0.08 g-mol) 4:1 WAG, 10-Slugs]

Figure 6.2 – Production History of Run LC7.

unrecovered [UREC] portion of oil remaining in the model at the end of the experiment.

The bar chart shows the oil recovery during each slug injection of the WAG process and distinguishes between oil recovery during carbon dioxide gas and water injection. Furthermore, the post-waterflood and blowdown recoveries are plotted to compare their relative efficiencies with the WAG process. The bar chart reflects the displacement efficiency of the process.

Discussion of Results

The main emphasis of this study was to determine the performance of the immiscible carbon dioxide WAG process at low pressure for the Lloydminster Aberfeldy field. As well, several other experiments were conducted on the two-dimensional model for another reservoir in the Lloydminster area.

For most of the parameters investigated a plot comparing the oil recovery curves is included. The bar chart (inset) reflects the relative efficiency of each curve by showing the recovery for each curve at a fixed point (dotted vertical line). The curve exhibiting the steepest initial slope is the most efficient.

Table 6.1 summarizes the twenty six displacement experiments conducted during this investigation. The table indicates the model used (linear core or two-dimensional), a brief process description including the WAG ratio (ratio of the total volume of water injected to the total volume of carbon dioxide injected) and operational variations, the model parameters (ϕ, k_{abs}, μ_o, S_{wc}, S_{oi}), the experimental parameters (operating pressure, CO_2 volume required to fully saturate the oil in place, CO_2 volume actually injected, moles of CO_2 injected), and the experimental results (CO_2-requirement CO_2-retention, injection flood life, phase oil recoveries).

A flowchart illustrating the various displacement experiments conducted is provided in Figure 6.3. This map of research experiments is divided into three main sections: Model Comparison,

Table 6.1

Summary of Immiscible Carbon Dioxide Displacement Experiments (1987 - 89)

Comments		Model Parameters					Experimental Parameters				Experimental Results						
								Carbon Dioxide			Carbon Dioxide			Phase Recoveries			
Run # Model —	Process Description	Ave Porosity [ø] (%)	Abs Perm [k] (darcies)	Oil Visc [μ] (mPa•s)	Water Sat [Swc] (%)	Oil Sat [Soi] (%)	Ave Press [p] (MPa)	Req to Saturate (HCPV)	Vol Inj (HCPV)	Moles Inj (g-mol)	Requirement [C-REQ] (sm3/sm3)	Retained [C-RET] (% inj)	Inj Flood Life (PV)	Process [P-Rec] (%HCPV)	Waterflood [W-Rec] (%HCPV)	Blowdown [B-Rec] (%HCPV)	Total Recovery [T-Rec] (%HCPV)
LC 1	1.92 HCPV WF	35.00	11.10	1059.0	7.00	93.00	1.00	0.00	0.00	0.00	0.00	0.00	1.79	0.00	39.14	0.00	39.14
LC 2	1.44 HCPV WF & v/2	35.00	5.58	1059.0	10.00	90.00	1.00	0.00	0.00	0.00	0.00	0.00	1.30	0.00	37.58	0.00	37.58
LC 3	4:1 WAG (10-Slugs)	36.60	10.66	1055.3	12.70	87.30	1.00	1.04	1.79	0.77	30.49	13.83	7.79	60.01	0.00	0.97	60.98
LC 4	4:1 WAG (10-Slugs)	36.30	11.54	1055.3	10.75	89.25	1.00	1.03	0.89	0.39	17.37	10.25	3.97	51.83	0.00	3.71	55.54
LC 5	4:1 WAG (5-Slugs)	35.63	10.81	1055.3	9.90	90.10	1.00	1.03	0.89	0.39	17.10	2.92	4.07	52.83	0.00	1.03	53.86
LC 6	4:1 WAG (1-Slug)	34.10	12.72	1055.3	10,80	89,20	1.00	1.03	0.89	0.39	24.85	5.97	3.48	46.04	0.00	0.33	46.37
LC 7	4:1 WAG (10-Slugs)	34.80	15.77	1055.3	9.42	90.58	1.00	1.03	0.20	0.09	4.44	8.37	2.82	33.91	12.72	0.34	46.97
LC 8a	2.11 HCPV WF	37.05	11.38	1055.3	10.31	89.69	1.00	0.00	0.00	0.00	0:00	0.00	1.90	0.00	38.81	0.00	38.81
LC 8b	4:1WAG Tert (10-Slugs)	37.05	11.38	1055.3	45.08	54.92	1.00	1.37	0.20	0.05	2.8/17.7	55.63	0.63	3.65/5.97	.30 / .49	3.26/5.33	46.0/11.8
LC 9	4:1 WAG (10-Slugs)	36.73	12.67	1055.3	9.96	90.04	1.00	1.03	0.10	0.04	2.34	6.01	2.37	26.92	17.44	0.29	44.65
LC10	4:1 WAG (10-Slugs)	35.77	10.98	1055.3	11.07	88.93	1.00	1.03	0.40	0.17	8.59	9.19	2.63	43.30	5.15	1.37	49.82
LC11	8:1 WAG (10-Slugs)	38.28	14.00	1055.3	10.05	89.95	1.00	1.03	0.20	0.09	4.59	8.00	2.73	38.38	6.59	0.61	45.58
LC12	2:1 WAG (10-Slugs)	38.40	16.15	1055.3	9.16	90.84	1.00	1.02	0.20	0.09	5.18	15.55	2.28	24.71	15.24	0.92	40.87
LC13	4:1 WAG (10-Slugs) v/2	36.22	12.12	1055.3	9.49	90.51	1.00	1.02	0.20	0.09	4.63	53.31	2.22	33.98	9.96	0.98	44.92
LC14	8:1 WAG (10-Slugs) v/2	36.93	12.05	1055.3	9.78	90.22	1.00	1.03	0.20	0.09	4.65	57.78	2.46	39.34	4.01	1.54	44.89
LC15	2:1 WAG (10-Slugs) v/2	36.57	12.06	1055.3	9.72	90.28	1.00	1.03	0.20	0.09	4.74	23.51	2.07	28.48	14.71	0.78	43.98
LC16	4:1 WAG (10-Slugs)	34.80	9.02	1059.0	20.90	79.10	2.50	1.02	0.64	0.77	29.71	93.91	3.05	46.38	3.56	2.79	52.73
LC17	4:1 WAG (10-Slugs)	37.70	12.30	1055.3	10.84	89.16	2.50	0.97	0.20	0.26	12.64	20.46	2.15	33.87	11.79	2.36	48.02
LC18	4:1 WAG (10-Slugs)	33.30	5.91	1059.0	10.30	89.70	5.50	0.76	0.21	0.74	43.43	100.00	2.96	31.49	14.79	0.53	46.81
LC19	4:1 WAG (10-Slugs)	34.40	12.36	1059.0	10.80	89.20	5.50	0.76	0.20	0.70	44.76	98.90	2.61	34.06	8.60	0.22	42.88
LC20	4:1 WAG (10-Slugs)	35.77	12.45	1055.3	10.66	89.34	5.50	0.76	0.20	0.77	37.76	80.04	2.60	34.67	14.09	0.30	49.07
LC21	4:1 WAG (10-Slugs)	36.69	15.09	1055.0	6.05	93.95	5.50	0.75	0.10	0.42	18.90	68.21	2.32	27.15	17.91	2.96	48.02
LC22	4:1 WAG, Wainwright	36.67	11.41	150.0	11.80	88.20	1.00	0.69 #	0.20	0.09	3.43	6.07	2.40	47.82	15.53	1.61	64.96
LC23a	2.29 HCPV WF,Wainwrt	36.22	11.46	150.0	12.95	87.05	1.00	0.00	0.00	0.00	0.00	0.00	1.99	0.00	60.71	0.00	60.71
LC23b	4:1 WAG Tert,Wainwrt	36.22	11.46	150.0	65.80	34.20	1.00	1.55	0.20	0.05	1.2/13.5	12.52	0.33	2.9/3.78	0.14/ 0.34	1.84/4.69	65.7/12.4
TD 1	4:1 WAG, Senlac	43.10	7.62	3295.0	13.24	86.76	2.50	0.99 *	0.61	1.41	45.38	48.91	2.78	39.39	0.00	1.47	40.86
TD 2	4:1 WAG, Senlac	41.50	7.41	3295.0	9.90	90.10	4.10	0.85 *	0.33	1.41	40.15	28.68	2.23	39.63	4.96	1.67	46.26
TD 3	4:1 WAG & v = 0.831	40.59	13.31	1055.3	8.67	91.33	1.00	1.02	0.20	0.16	4.83	65.99	2.12	31.50	10.07	1.73	43.30

Table 6.1 (con't)

Summary of Immiscible Carbon Dioxide Displacement Experiments (1987 - 89)

Abbreviations, Symbols, and Descriptions

CO2 Mass Injection Rate (308 cm3/hr):

@ 0.10 MPa = 0.013 g-mol / hr
@ 1.00 MPa = 0.134 g-mol / hr
@ 2.50 MPa = 0.371 g-mol / hr
@ 5.50 MPa = 1.189 g-mol / hr

Average Flow Velocity (v) For All Runs = 0.984 m/d, except where noted as a fraction
Average Injection Rate For All Runs = 308 cm3/hr @ Reservoir Conditions

CO2 Requirement = Total CO2 Injected (std. cond.) / Total Oil Produced
CO2 Retained = Percentage of Total CO2 Injected Not Produced
Total Recovery = Process Recovery + Waterflood Recovery + Blowdown Recovery

Water Mass Injection Rate (308 cm3/hr) = 17.90 g-mol / hr

HCPV Basis / RHCPV Basis
RHCPV = Residual oil left in the model after waterflooding

Aberfeldy Solubility:	Rso (sm3/m3)	Rsw (sm3/m3)	
@ 1.00 MPa	10.14	4.97	HCPV CO2 Required to Saturate @ 1.00 MPa = { Rso + [Rsw x (1/Soi - 1)] } x 0.096089
@ 2.50 MPa	26.86	10.74	HCPV CO2 Required to Saturate @ 2.50 MPa = { Rso + [Rsw x (1/Soi - 1)] } x 0.034584
@ 5.50 MPa	68.51	19.91	HCPV CO2 Required to Saturate @ 5.50 MPa = { Rso + [Rsw x (1/Soi - 1)] } x 0.010791

* SENLAC solubility estimates based upon Aberfeldy values
# Wainwright solubility estimates based upon oil density = 0.943 g/cc & Rso = 1.64 wt% CO2 @ 1.0 MPa
= 8.57 sm3/m3 @ 1.0 MPa

LC = Linear Core Model
TD = Two-Dimensional Model

Inj Flood Life = Total PV fluid Injected until an instantaneous producing WOR of ≈ 20:1 is reached

Linear Model, and Two-Dimensional Model. The model comparison was conducted to test the effect of pattern and scaling. The two-dimensional model represents a quarter of a five-spot while the linear core model represents a direct line drive, both for the same prototype. The linear model displacements were conducted to determine the effect of several parameters on the immiscible carbon dioxide process. The two-dimensional model runs were conducted to evaluate the process for two Saskatchewan heavy oil reservoirs.

Several additional experiments were conducted, but not included, to check the repeatability of results for some of the runs. Total oil recovery was found to be within ±0.5% HCPV.

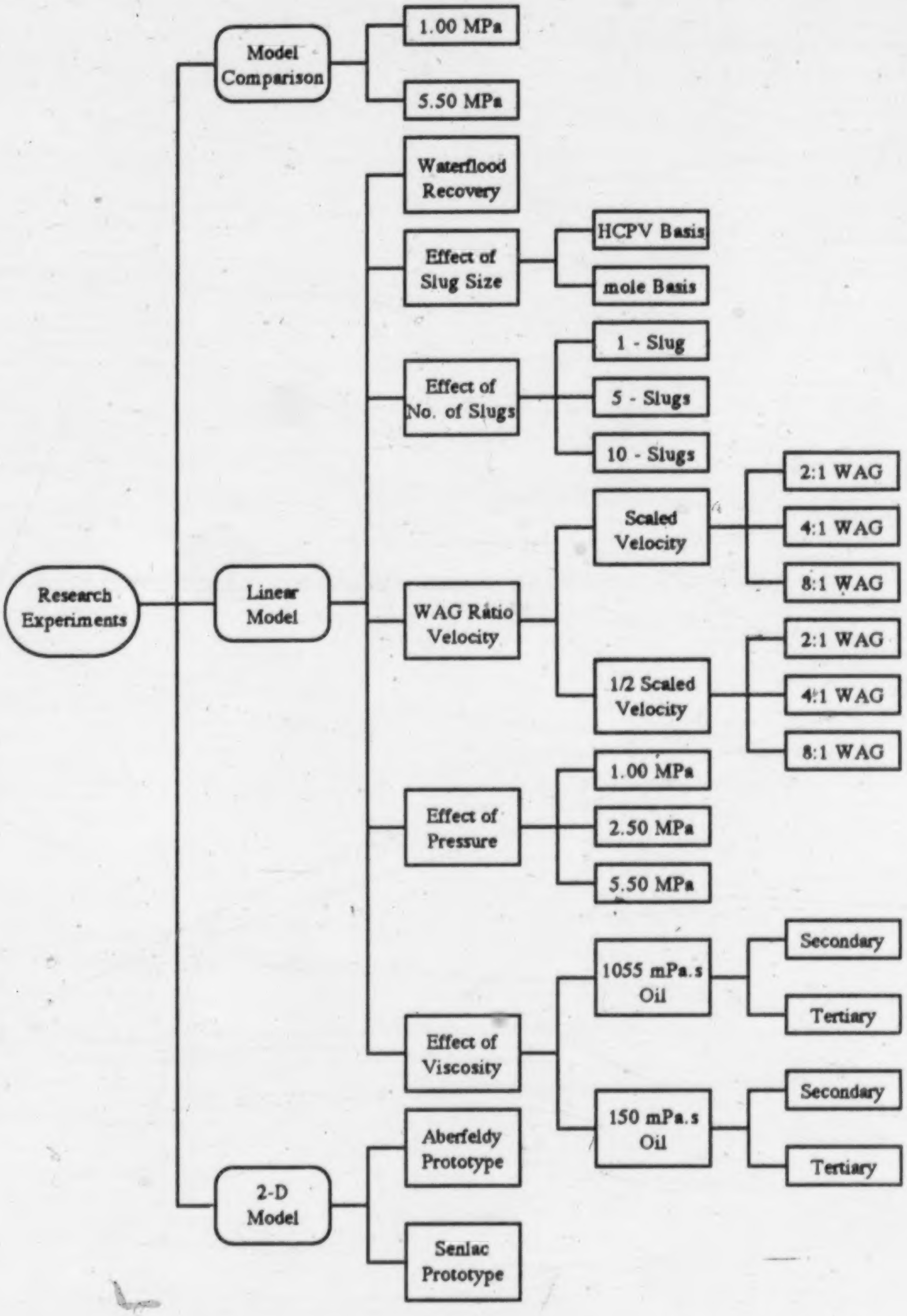

Research Experiments
Model Comparison
1.00 MPa
5.50 MPa
Linear Model
Waterflood Recovery
Effect of Slug Size
HCPV Basis
mole Basis
Effect of No. of Slugs
1 - Slug
5 - Slugs
10 - Slugs
WAG Ratio Velocity
Scaled Velocity
2:1 WAG
4:1 WAG
8:1 WAG
1/2 Scaled Velocity
2:1 WAG
4:1 WAG
8:1 WAG
Effect of Pressure
1.00 MPa
2.50 MPa
5.50 MPa
Effect of Viscosity
1055 mPa.s Oil
Secondary
Tertiary
150 mPa.s Oil
Secondary
Tertiary
2-D Model
Aberfeldy Prototype
Senlac Prototype

Figure 6.3 - Map of Displacement Experiments Conducted During the Research Project.

Model Comparison

In order to show the capabilities of scaled models and the effects of flood pattern, the results of the linear core model (line-drive) were compared with the two-dimensional model (quarter of a five-spot). This is important because the scaling criteria, as applied to the two-dimensional model, were used in the design of the linear core model. Model comparisons were conducted for both high (5.50 MPa) and low (1.00 MPa) pressure experiments.

For both the high and low pressure comparisons the following variables were held constant in both models:

operating pressure and temperature;
process: 20% HCPV CO_2 4:1 WAG, 10-slugs;
fluids and porous medium (1055 mPa•s oil & Ottawa sand).

The scaling group of gravitational-to-viscous forces, represented by the ratio of permeability-to-flow velocity (k/v), was also nearly the same for the two models.

Low Pressure (1.00 MPa) Comparison

The low pressure comparison was conducted utilizing Runs LC7 and TD3 (Table 6.1). For the low pressure comparison, both runs had almost identical gravitational-to-viscous force ratios.

$$(k/v)_{TD} = 16.0294 \qquad (k/v)_{LC} = 16.0264$$

It is shown in Figure 6.4 that the final oil recovery for the linear core model (46.97%) was slightly higher than the oil recovery for the two-dimensional model (43.30%). The recovery curves between the two models is essentially identical except that the flood life of the two-dimensional model was approximately 25% shorter (see Table 6.1).

As discussed previously, the areal and vertical sweep efficiencies of the linear core model are assumed to be unity. The design of the two-dimensional model attempts to account for sweep effects in the element of symmetry formed by a quarter of a five-spot pattern. The

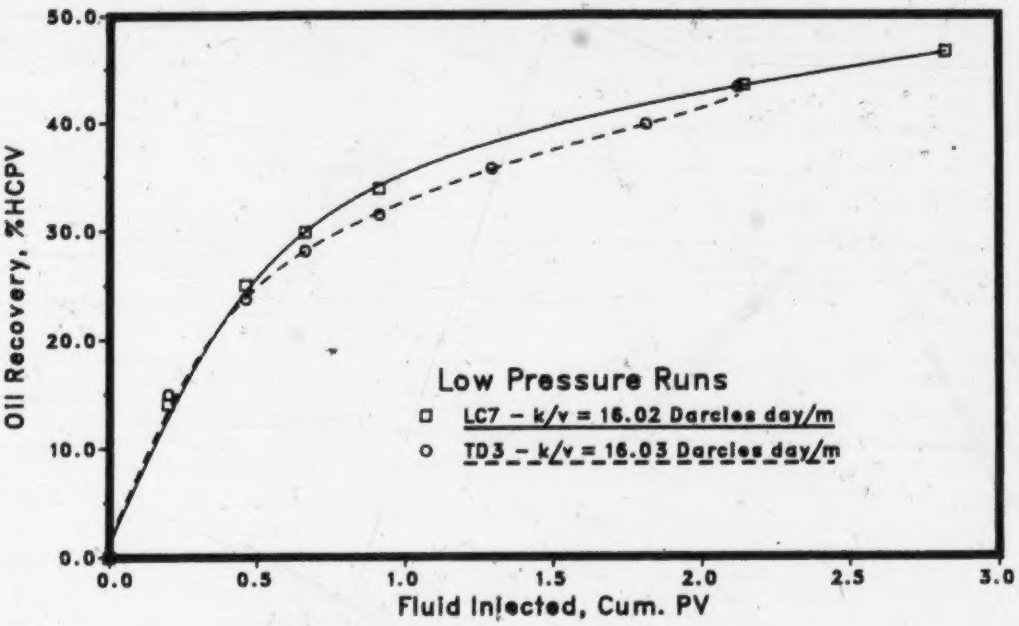


Figure 6.4 – Recovery of Linear [LC] and Areal [TD] Low Pressure [1.00 MPa] Scaled Models.

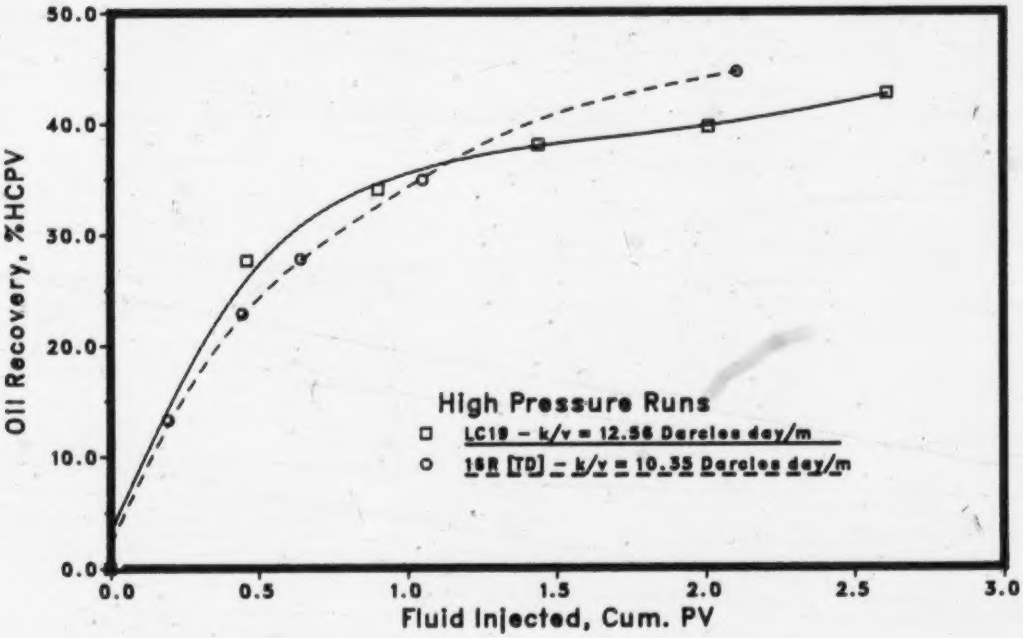


Figure 6.5 – Recovery of Linear [LC] and Areal [TD] High Pressure [5.50 MPa] Scaled Models.

difference in sweep effects thus may account for the difference in total oil recoveries.

Oil recovery for the various phases was similar. The major difference occurred during the blowdown phase, where recovery was approximately five times higher in the two-dimensional model. The carbon dioxide requirement in both models was very similar. However, the carbon dioxide retention was much higher in the two-dimensional model. The higher retention in the two-dimensional model is most likely due to effects of geometry which will inhibit the areal conformance of the injected carbon dioxide gas. As well, the production and injection ports are much smaller in the two-dimensional model. This may explain why the blowdown recovery was so much higher in the two-dimensional model.

High Pressure (5.50 MPa) Comparison

Runs 16R (Table 4.1) and LC19 (Table 6.1) were used for the high pressure model comparison. For the high pressure comparison, both runs had very similar gravitational-to-viscous force ratios.

$$(k/v)_{TD} = 10.3542 \qquad (k/v)_{LC} = 12.5610$$

It is shown in Figure 6.5 that the final oil recovery for the two-dimensional model (47.50%) was higher than the recovery for the linear core model (42.88%). Again the recovery curves are similar but the linear core model initially gave better results, viz. steeper initial slope of the recovery curve. This may be due to the higher sweep efficiency in the linear core model. The point where the curves intersect [≈1 PV] corresponds to the beginning of the post-waterflood phase. This indicates that the post-waterflood phase will recover more oil in the two-dimensional model than the linear core model.

As for the low pressure comparison, carbon dioxide requirements were approximately the same for the high pressure comparison. As discussed earlier, problems associated with measuring produced gas volumes (DTM) gave abnormally high values of carbon dioxide retention in some runs. The author feels this is the case for

Run LC19, carbon dioxide retention = 98.9% injected, and that a much lower value would better reflect the true result.

Comparison of the models at both high and low pressures shows that the scaling criteria considered may be used when comparing the two models. Differences in total oil recovery may be accounted for by differing sweep effects between the two patterns studied. Carbon dioxide requirements were very similar for both models while carbon dioxide retention was higher for the two-dimensional model. The effect of areal conformance is significant when comparing the two models. Areal conformance is greater in the linear model due to the symmetric geometry. As well, areal conformance increases with pressure due to the increased viscosity of the injected carbon dioxide gas. Thus, for an accurate prediction of a field, the two-dimensional model is recommended.

Linear Core Model Displacement Results

Twenty three linear core displacement experiments were conducted during this investigation. The majority of these experiments were aimed at optimizing the performance of the immiscible carbon dioxide WAG process at a low pressure. The WAG displacement experiments were divided into six areas of study:

1. Waterflood Recovery at 1.00 MPa;
2. Effect of Total CO_2 Slug Size at 1.00 MPa;
3. Effect of Number of WAG Slugs at 1.00 MPa;
4. Effect of WAG Ratio and Velocity at 1.00 MPa;
5. Effect of Operating Pressure;
6. Effect of Initial Oil Viscosity at 1.00 MPa (secondary and tertiary).

Waterflood Recovery

It is important to examine waterflood recovery in order to show the relative effectiveness of the carbon dioxide WAG process. During the early stages of this work, two waterflood runs (LC1 and LC2) were conducted to test the new model as well as establishing a base-line for comparison purposes. The velocity in Run LC2 was half of that in Run LC1 due to the much lower pack permeability (see Table 6.1). Oil recovery in Runs LC1 and LC2 was 39.14 and 37.58% HCPV, respectively. Runs LC8(a) and LC23(a) employed a waterflood prior to the carbon dioxide WAG process. Oil recovery in Runs LC8(a) and LC23(a) was 38.81 and 60.71% HCPV, respectively. The oil viscosity in Runs LC1, LC2, and LC8(a) was approximately seven times that of Run LC23(a). Subsequently, the displacement efficiency of Run LC23(a) was much better than in the other runs (see Figure 6.6). The end-point producing WOR for all waterflood runs was approximately 20:1.

The waterflood recoveries obtained from the linear core experiments are approximately twice those normally observed in Saskatchewan heavy oil reservoirs (prototypes). The main reason for

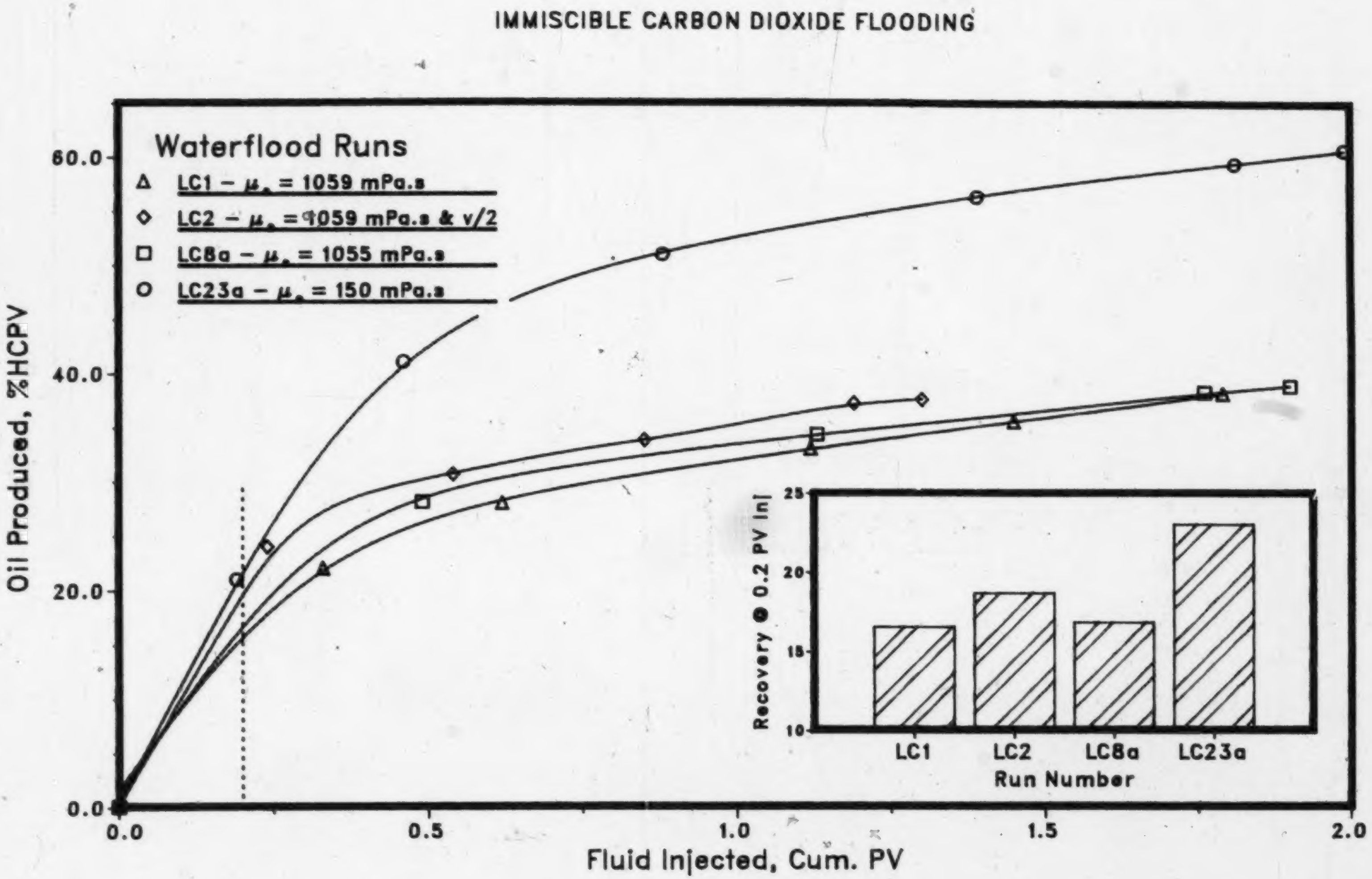


Figure 6.6 – Linear Core Waterflood Runs at 1.00 MPa.

the higher model recoveries is the homogeneity of the sand pack in the model. In contrast, the heavy oil reservoirs in Saskatchewan tend to be rather unconsolidated and heterogeneous, and often suffer from considerable sand production[15].

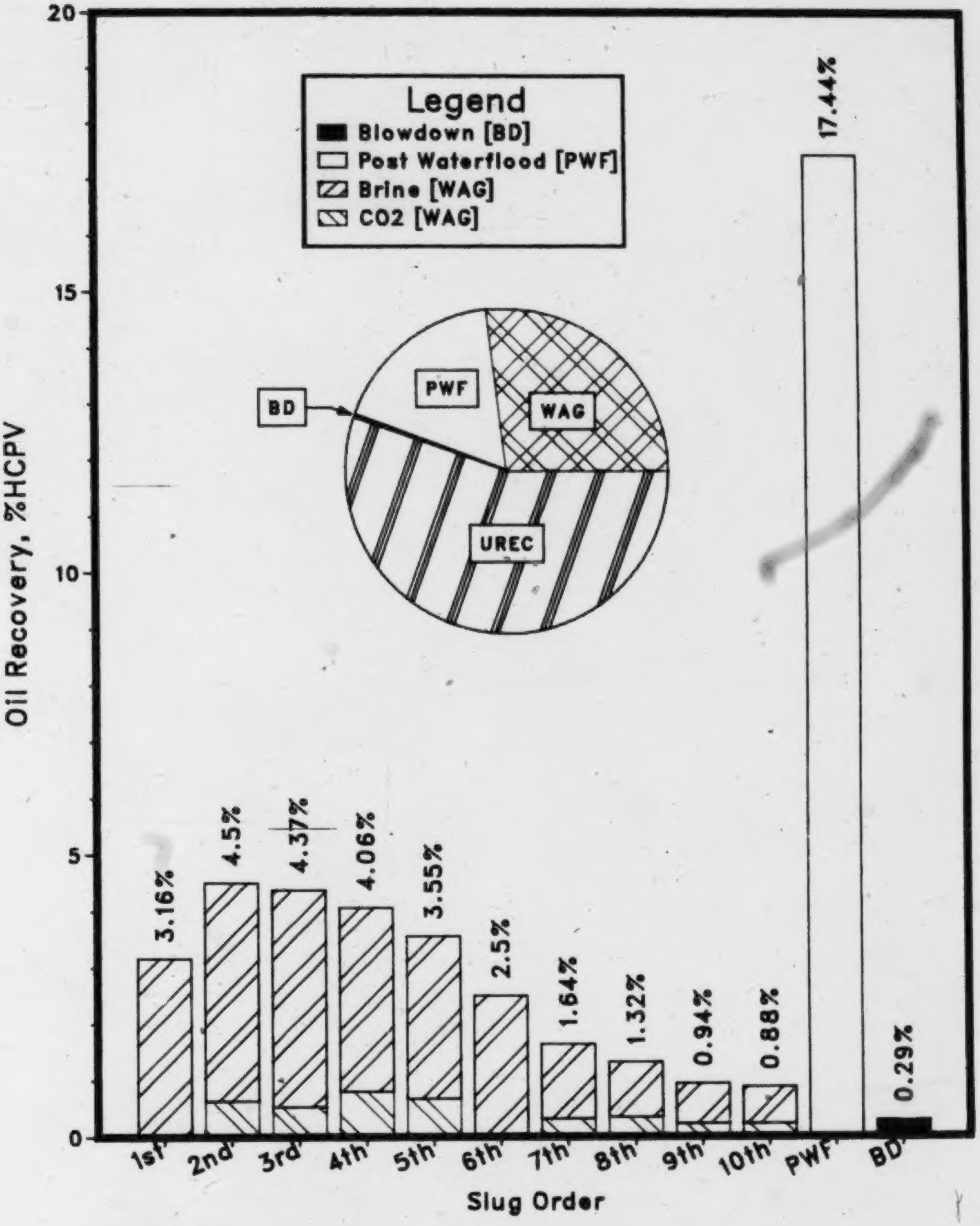
The results show that the waterflood recovery is sensitive to oil viscosity, and that the average waterflood recovery, in the linear core model, for a 15°API (1055 mPa•s) heavy oil is approximately 38.51% HCPV.

Effect of Total Carbon Dioxide Slug Size

Five experiments were employed to determine the sensitivity of oil recovery to the total carbon dioxide slug size at low pressure. The 4:1 WAG process at 1.00 MPa, with ten WAG slugs at constant velocity, was utilized for all five runs. Two methods were used in calculating the total carbon dioxide slug size. For Runs LC3 and LC4, the total carbon dioxide slug size was calculated on a molar basis. The volume of carbon dioxide for Run LC3 was calculated to be equal to the same number of moles required for a 20% HCPV slug at 5.5 MPa. Run LC4 utilized half the number of moles in Run LC3. Runs LC7, LC9, and LC10 were calculated on a volumetric basis at prevailing reservoir conditions (1.00 MPa and 23°C). The total carbon dioxide slug size for Run LC10 was twice that of Run LC7, and four times that of Run LC9.

Figures 6.7 through 6.11 show the oil recovery distribution of Runs LC9, LC7, LC10, LC4, and LC3, respectively. These figures are arranged in order of ascending total carbon dioxide slug size (volumetric basis). Note that for Runs LC3 and LC4 the post-waterflood recovery is absent. This is because a 20:1 water-oil ratio had been reached or exceeded at the end of the WAG process. These figures show that the largest, or close to, portion of oil recovery occurred during the first slug [CO_2+H_2O] injected. This is because breakthrough did not occur until the end of the first or during the second WAG slug. Also, the recovery during the first slug [CO_2+H_2O] injected increased with slug size (see Figure 6.12). The dotted straight line of Figure 6.12 represents a linear relationship between first slug oil recovery and first slug size, i.e. oil recovery doubles as slug size doubles. The linear relationship vanishes at approximately 4.51% HCPV (45% HCPV total carbon dioxide slug size) possibly giving an efficiency maximum. Also note that oil recovery due to carbon dioxide gas displacement (bottom portion of bar) only occurs in Runs LC3 and LC4 where the carbon dioxide slug size was very large relative to Runs LC7, LC9, and LC10.

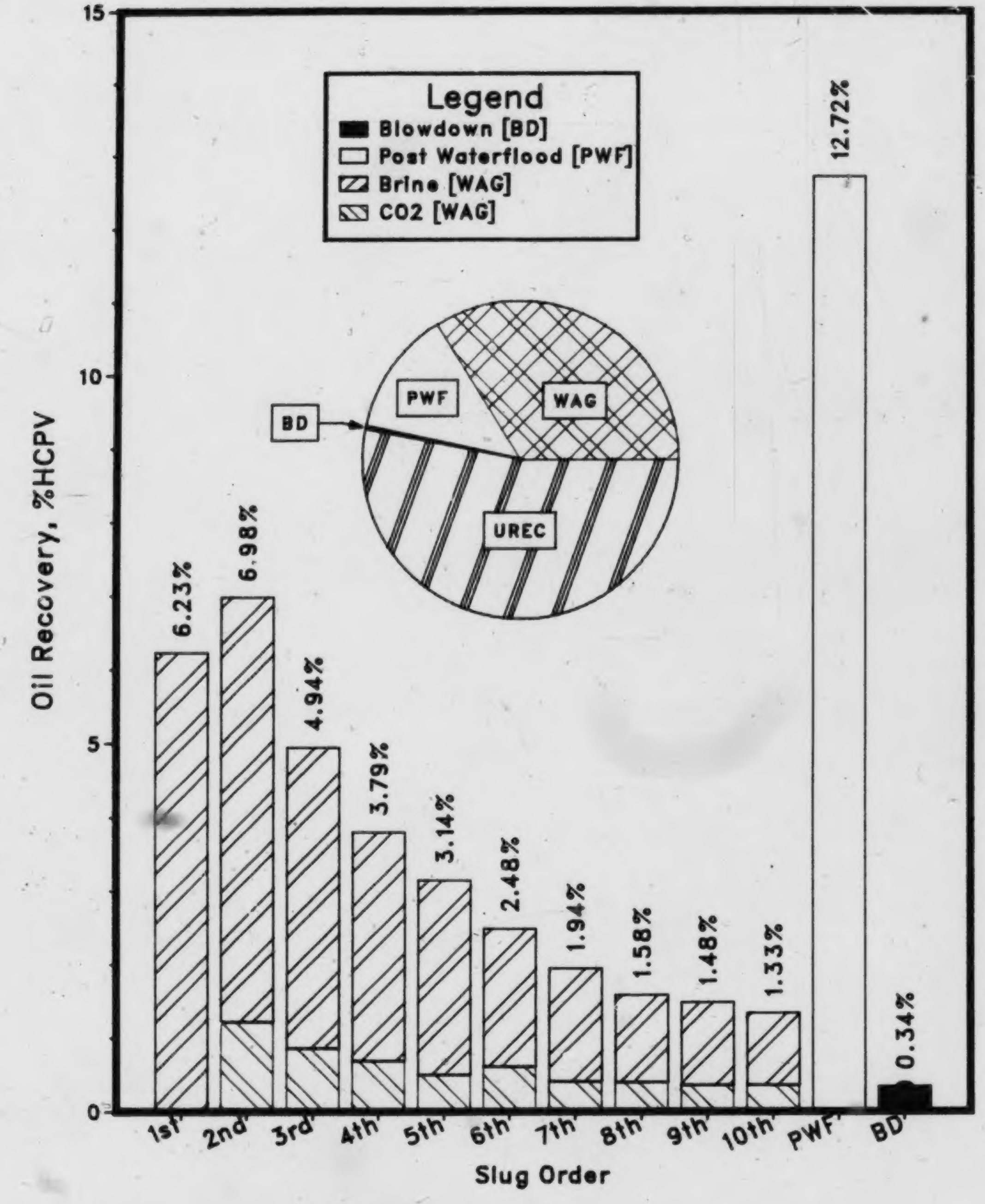
For Runs LC7, LC9, and LC10, the dominant portion of the total recovery occurred during the post-waterflood phase. This shows the



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 36.73 %, k = 12.667 darcies, S_o = 90.04 %, S_{wc} = 9.96 %

[0.10 HCPV CO2 @ 1.00 MPa (0.04 g-mol) 4:1 WAG, 10-Slugs]

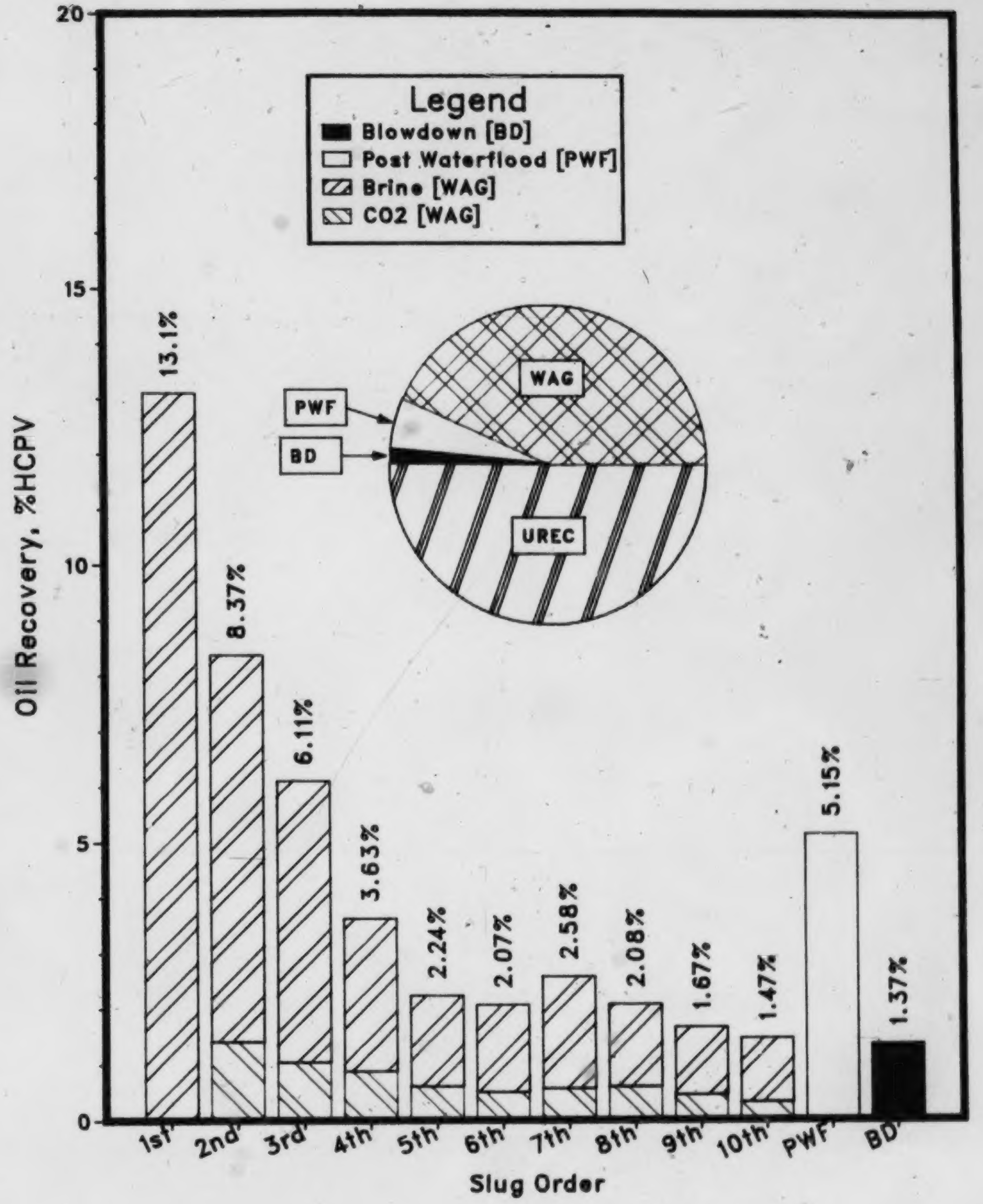
Figure 6.7 Oil Recovery Distribution of Run LC 9.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 34.80 %, k = 15.774 darcies, S_o = 90.58 %, S_{wc} = 9.42 %

[0.20 HCPV CO2 @ 1.00 MPa (0.08 g-mol) 4:1 WAG, 10-Slugs]

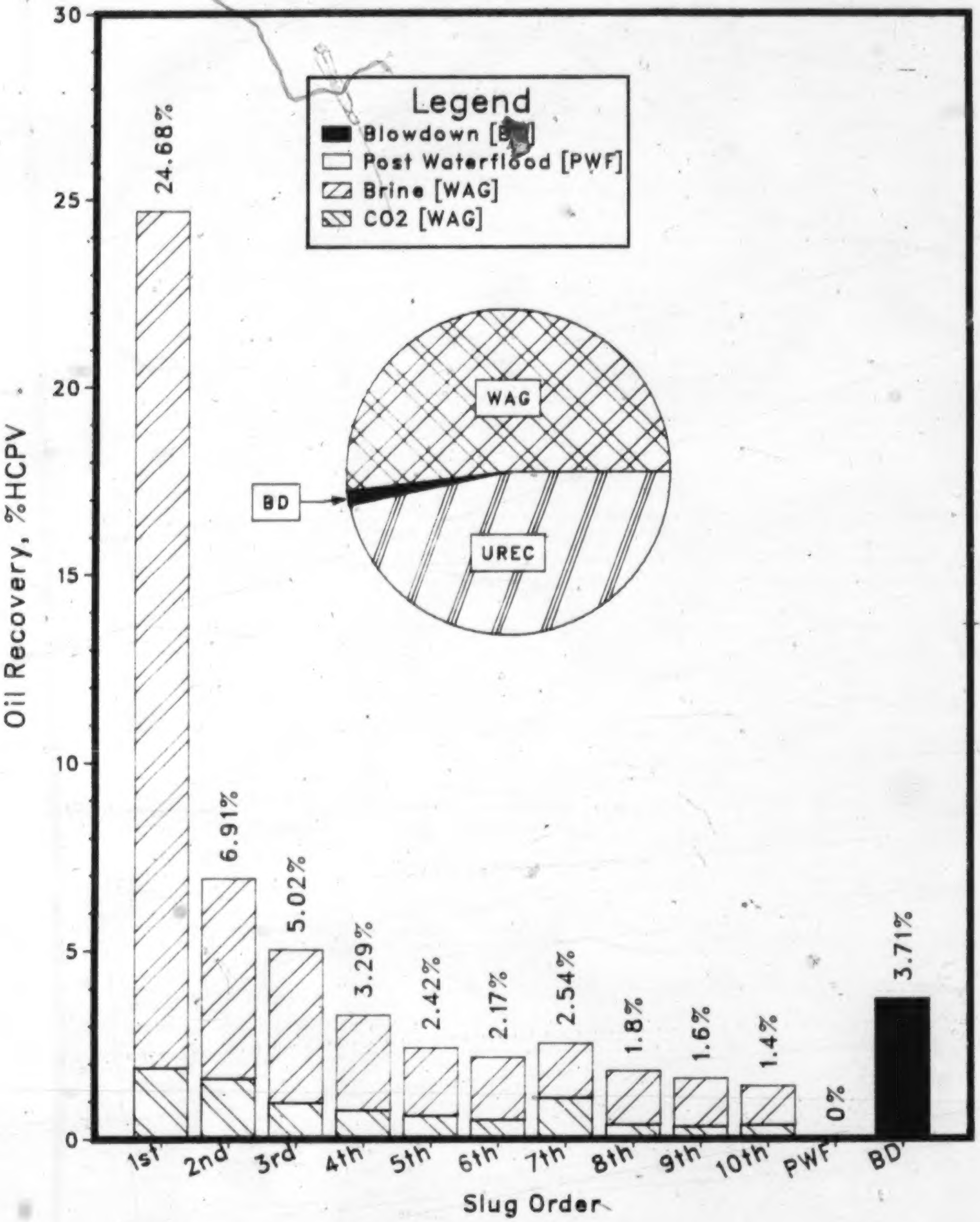
Figure 6.8 Oil Recovery Distribution of Run LC 7.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 35.77 %, k = 10.978 darcies, S_o = 88.93 %, S_{wc} = 11.07 %

[0.40 HCPV CO2 @ 1.00 MPa (0.17 g-mol) 4:1 WAG, 10-Slugs]

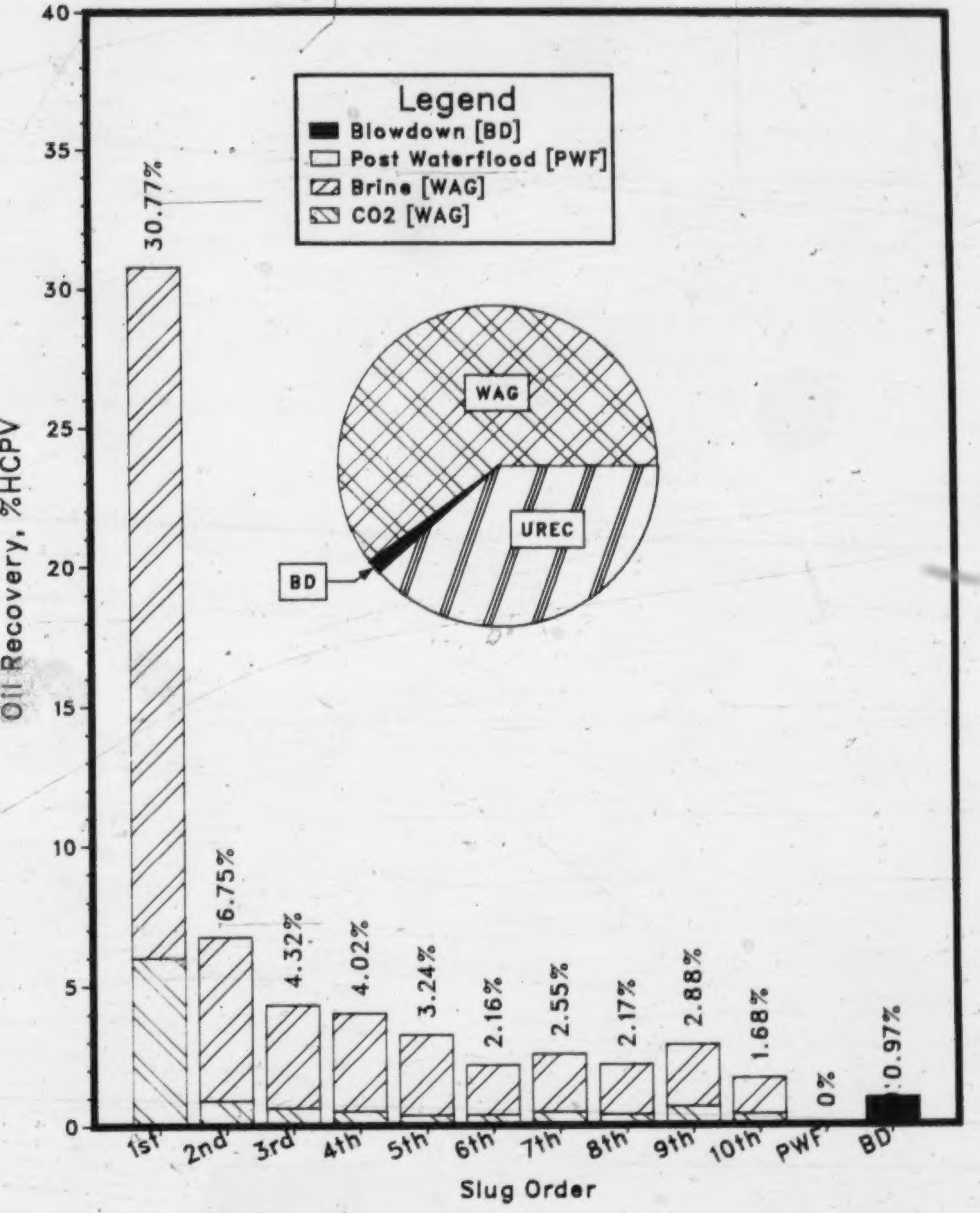
Figure 6.9 Oil Recovery Distribution of Run LC10.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 36.32 %, k = 11.538 darcies, S_o = 89.29 %, S_{wc} = 10.71 %

[0.89 HCPV CO2 @ 1.00 MPa (0.39 g-mol) 4:1 WAG, 10-Slugs]

Figure 6.10 Oil Recovery Distribution of Run LC 4.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 36.60 %, k = 10.657 darcies, S_o = 87.32 %, S_{wc} = 12.70 %

[1.79 HCPV CO2 @ 1.00 MPa (0.77 g–mol) 4:1 WAG, 10–Slugs]

Figure 6.11 Oil Recovery Distribution of Run LC 3.

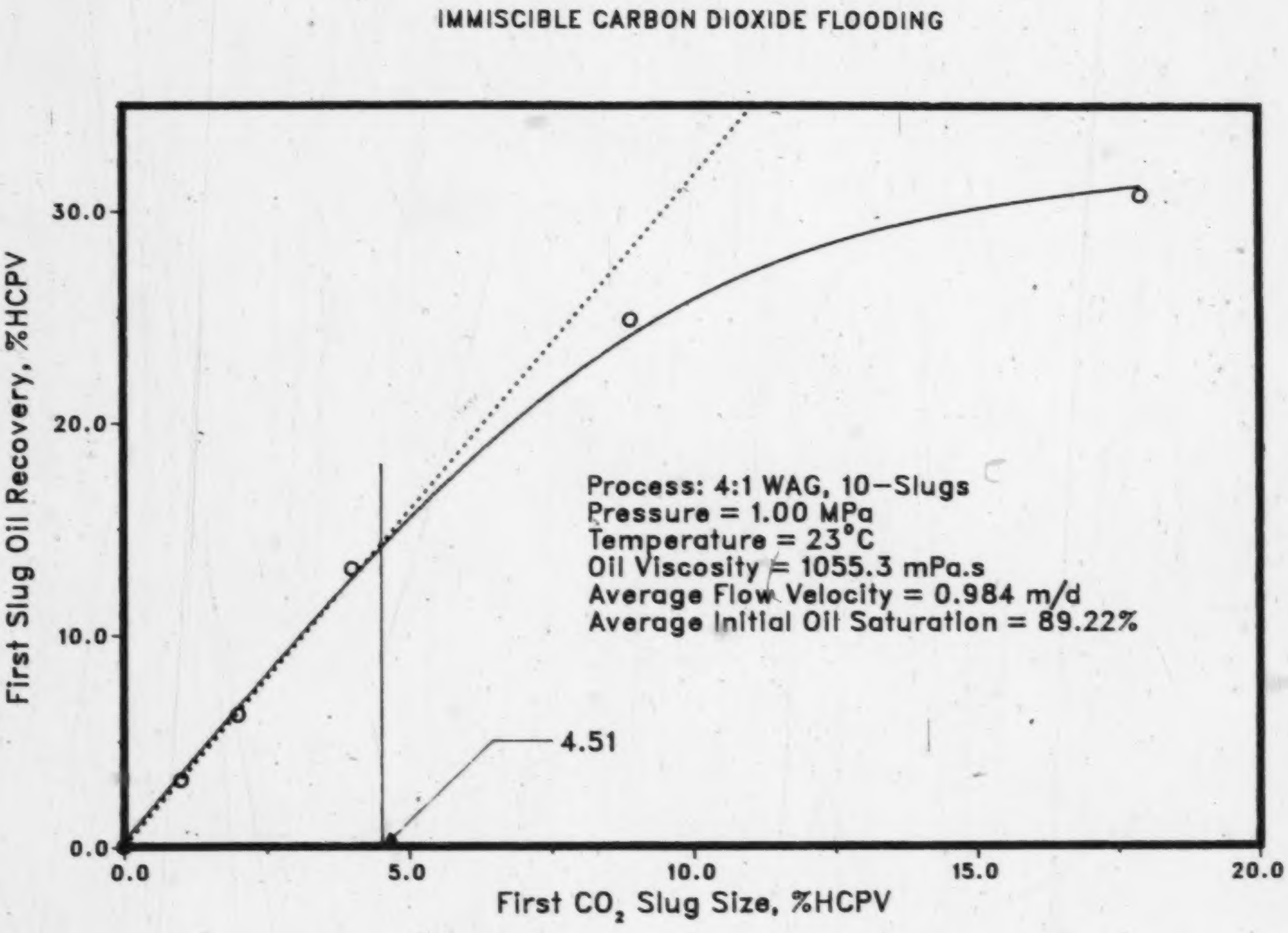


Figure 6.12 – First Slug Oil Recovery vs. First CO_2 Slug Size.

potential of a relatively small volume of carbon dioxide to appreciably extend the flood life of a project. The dominance of the first slug oil recovery may be analogous to results reported by Patton *et al*[10] for the carbon dioxide "huff-n-puff" process. They found that the largest portion of oil recovery always occurred during the first cycle.

Figure 6.13 shows the effect of total carbon dioxide slug size on producing gas-oil ratio. Note how the 20% slug gas-oil ratio curve behaves nearly the same as that for the 10% slug, and that the curves for the larger slugs rise more rapidly, indicating an inefficient use of carbon dioxide and the increased surface handling costs in a field test.

Figure 6.14 illustrates the effect of total carbon dioxide slug size on oil recovery at 1.00 MPa. The bar chart (inset) reflects the slope of the initial straight line portion of the curve. Run LC9 (10%-slug) exhibited the steepest slope during the initial displacement. This is due to water injection at a relatively early stage, leading to a more stable displacement. The initial slope of Run LC7 and Run LC10 are approximately equal, therefore the 20%-slug is utilized more efficiently than the 40%-slug.

Run LC3 had the longest flood life and the highest total oil recovery (Table 6.2). However, the overall ratio of total oil recovery to injection flood life shows that Run LC10 (40%-slug) recovered oil approximately two and one-half times faster than Run LC3 (179%-slug) utilizing less than one-quarter the total volume of carbon dioxide. Although the overall ratio of recovery to flood life (Table 6.2) indicates that waterflooding recovers oil the fastest, total recovery is limited. However, the 40% CO_2 WAG process increased oil recovery greater than 10 percentiles over a waterflood in less than one and one-half times the flood life.

Figure 6.15 illustrates the three recovery phases of the immiscible carbon dioxide flooding process and how they are affected by the total carbon dioxide slug size. As expected, total oil recovery increases with carbon dioxide slug size.

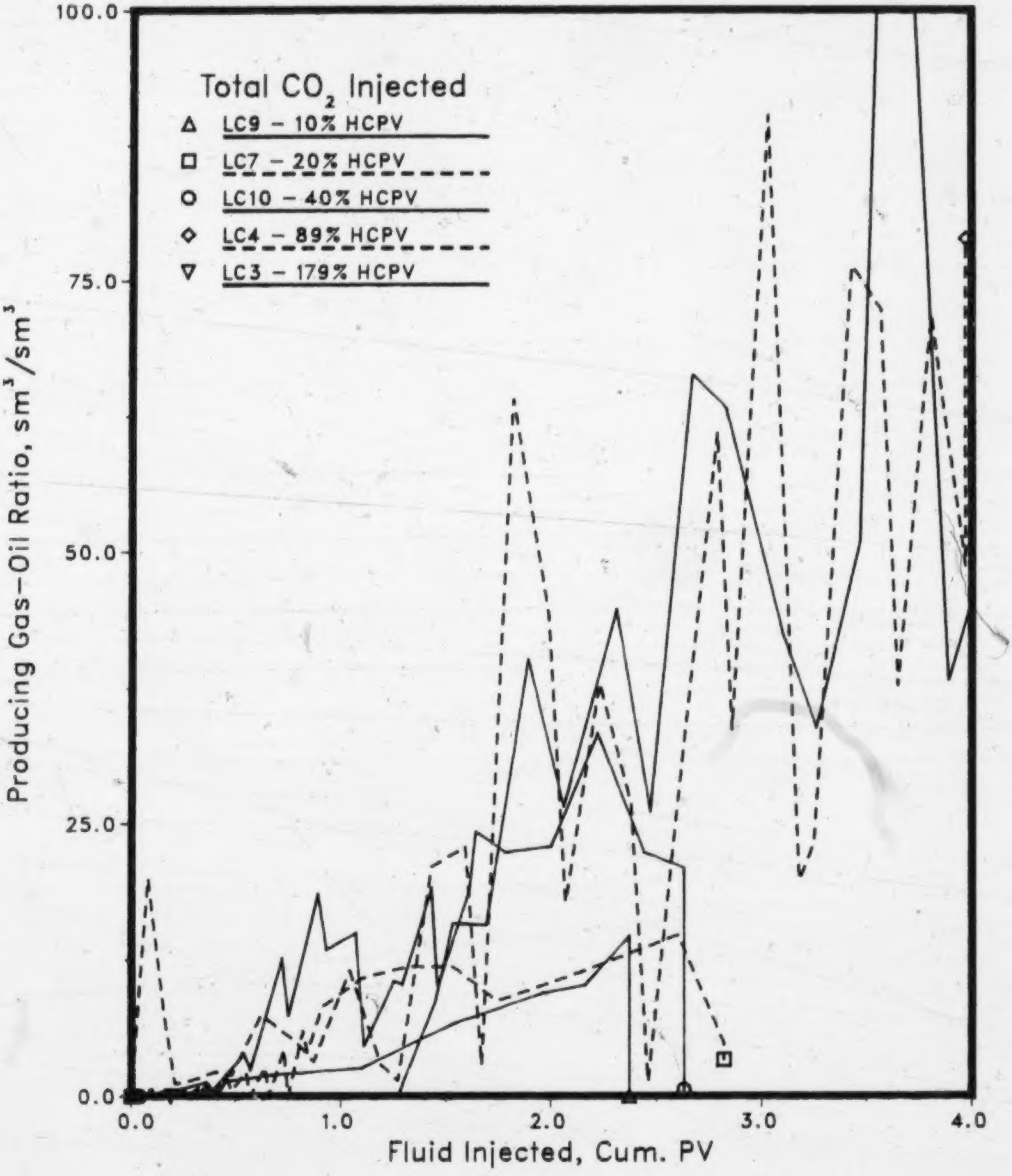


Figure 6.13 – Effect of Total CO_2 Slug Size on Producing Gas–Oil Ratio.

Table 6.2

Effect of Total Carbon Dioxide Slug Size on Rate of Oil Recovery

Run* Number (LC)	Total CO_2 Injected (%HCPV)	Injection† Flood Life (PV)	Total Oil Recovered (%HCPV)	Ratio of Recovery to Flood Life (%Rec/PV)
1	0.0	1.79	39.14	21.87
9	10.0	2.37	44.65	18.84
7	20.0	2.82	46.97	16.66
10	40.0	2.63	49.81	18.94
4	89.0	3.97	55.54	13.99
3	179.0	7.79	60.98	7.83

* 4:1 WAG Process at 1.00 MPa and velocity is constant at 0.984 m/d.

† Total volume of fluids injected when 20:1 WOR is reached.

This increase in oil recovery is significant up to the 40.0%-slug. The post-waterflood recovery drops significantly as carbon dioxide slug size increases. The point at 0.0% total CO_2 represents the average waterflood recovery. An interesting phenomenon is the gradual rise and fall of the blowdown recovery phase. This indicates that an excess of carbon dioxide may be inefficiently utilized (more rapid fingering) during the blowdown recovery phase. Evidence of excess carbon dioxide injection is also seen in the rapid rise of the producing gas-oil ratios for the larger slug sizes (see Figure 6.13). A possible remedy for recovering some of this lost drive energy may be to inject proportionally more carbon dioxide during the early stages of the experiment to capitalize on the high oil recoveries during the first slug injection.

Several other factors must be taken into account when determining the optimum total carbon dioxide slug size. One of the most important is the additional cost of carbon dioxide associated with recovering incremental oil. This factor is represented by the carbon

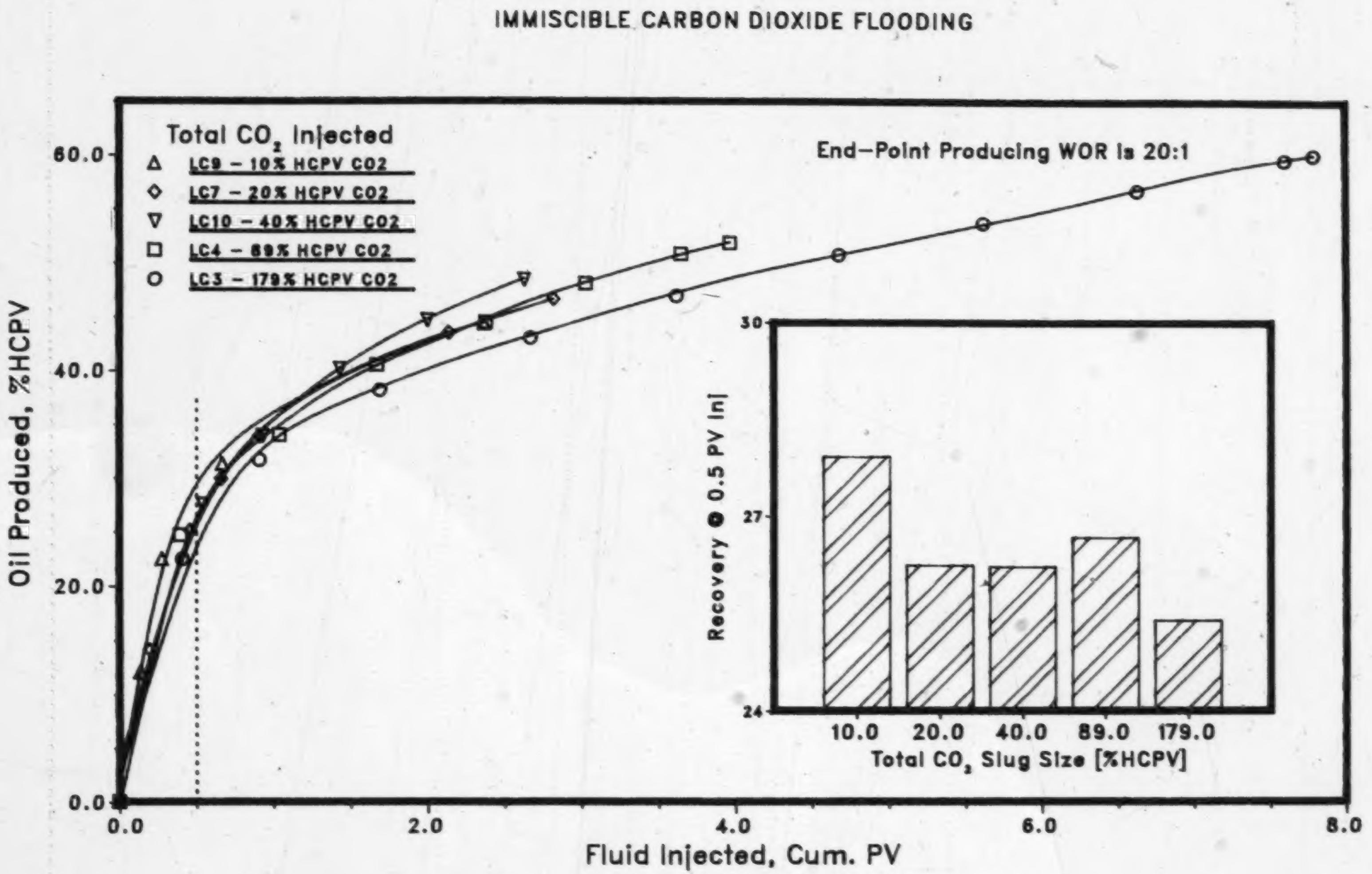


Figure 6.14 – Effect of Total CO$_2$ Slug Size on Oil Recovery at 1.00 MPa.

dioxide requirement. This parameter is not the same as gross carbon dioxide requirement, as reported in some of the literature, which accounts for the reinjection of produced carbon dioxide. Carbon dioxide retention calculations can be used for determining the gross carbon dioxide requirement.

Figure 6.16 shows the carbon dioxide requirement and retention for the various slug sizes. The carbon dioxide requirement increases with total carbon dioxide slug size. For the smaller slugs, carbon dioxide requirements are less than 10 sm^3/sm^3. Since the scaled model does not account for heterogeneities of the prototype and carbon dioxide leakoff outside the pattern, the values of carbon dioxide requirement would have to be adjusted upward for field application. Even considering inflated carbon dioxide requirements, these values would still fall well below the carbon dioxide requirements for miscible projects, which generally are in the range of 1500 to 3000 sm^3/sm^3. Carbon dioxide requirements for the immiscible displacement of heavy oil are lower than those required for the miscible displacement of light oils. This is due to the fact that the mole fraction of carbon dioxide in the CO_2-oil mixture required to saturate a heavy oil is lower than that to achieve miscibility between carbon dioxide and light oil[22], because the latter is a multi-contact process.

Figure 6.16 also shows that the higher the overall carbon dioxide retention, the higher the total oil recovery. The retention for Runs LC3 and LC4, 89%- and 179%-slug, respectively, are slightly misleading due to the problem associated with measuring the volume of produced gas. The author feels that these values should be higher than depicted.

Previous investigators[15,22] have suggested that a total carbon dioxide slug size of 20% HCPV is the optimum based upon high oil recovery and low carbon dioxide requirement. This conclusion is based on a limited number of runs, using the two-dimensional model, utilizing two other slug sizes. Results from the present work, conducted on the linear core model, suggest that the optimum total

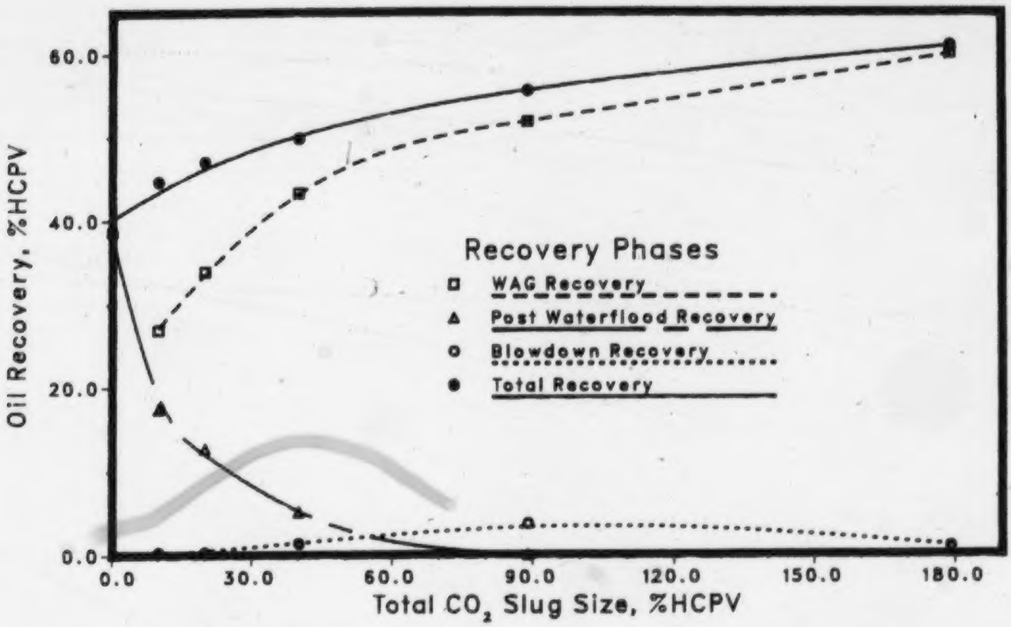


Figure 6.15 – Effect of Total CO_2 Slug Size on Recovery Phases for the 4:1 WAG Process at 1.00 MPa.

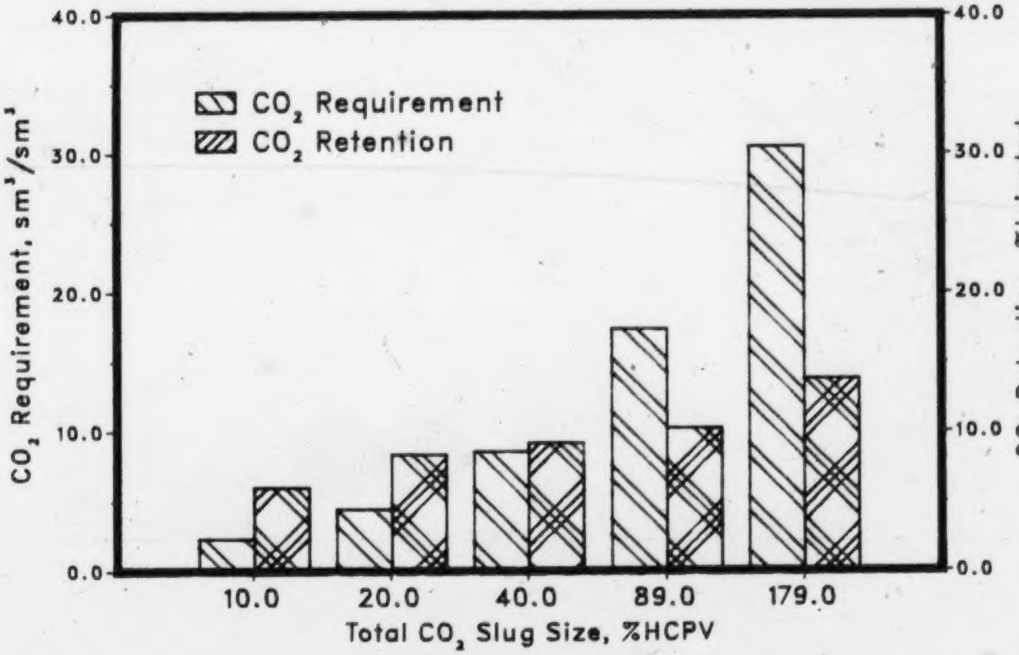


Figure 6.16 – Effect of Total CO_2 Slug Size on CO_2 Requirement and CO_2 Retention for the 4:1 WAG Process at 1.00 MPa.

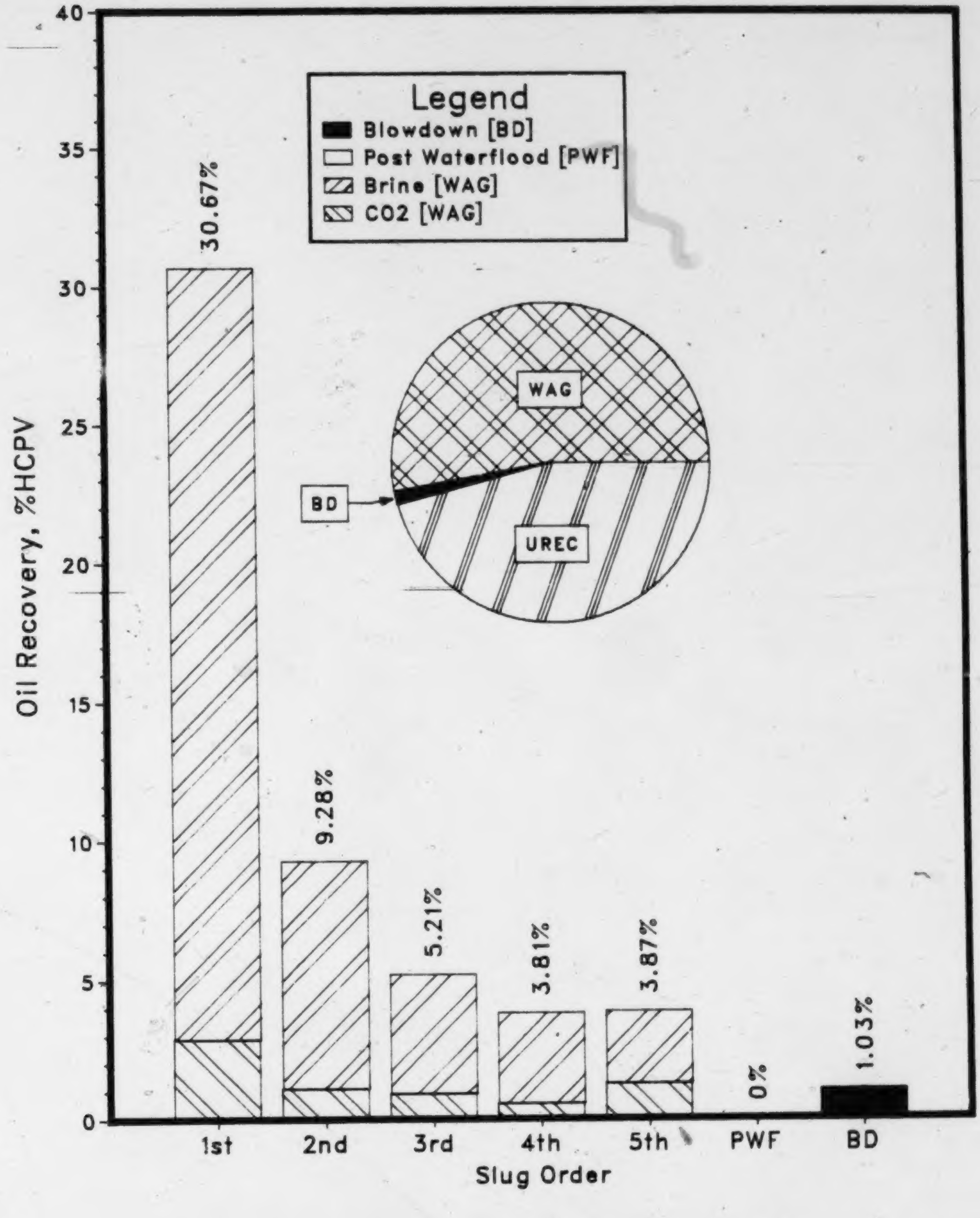
carbon dioxide slug size is in the range of 35 to 40% HCPV. The discrepancy between optimum slug size in the two models may be explained by the variation in areal conformance. An equal volume of carbon dioxide contacts a larger portion of the oil in the linear core model resulting in increased oil recovery. For very large slug volumes, greater than 40% HCPV, it appears that they are less efficiently utilized and that gas channeling occurs faster.

Effect of Number of WAG Slugs

Three experiments at 1.00 MPa were employed to determine the sensitivity of oil recovery to the number of WAG slugs at low pressure. This parameter was considered to be important and is therefore distinguished from the effect of total carbon dioxide slug size. The 4:1 WAG process, at constant velocity, was utilized for all three runs. The total volume (mass) of carbon dioxide injected was 89.0% HCPV (0.39 g-mol) for all runs. Run LC4 utilized ten WAG slugs, Run LC5 utilized five WAG slugs, and Run LC6 utilized a single WAG slug to complete the water-alternating-gas displacement process.

Figures C.4 through C.6 show the production history of Runs LC4, LC5, and LC6, respectively. Figure C.6 (single-slug) illustrates the inefficient use of carbon dioxide and the delay in oil production (OPFIR) of the single slug process. Carbon dioxide breakthrough occurred very early in this experiment, and the benefits associated with carbon dioxide were lost in the latter stages. Note also how the oil-produced:fluid-injected ratio is suppressed until waterflooding begins [≈0.75 PV], and that the life of this flood is significantly shorter [≈0.6 PV] than Runs LC4 and LC5. Figure 6.17 shows the oil recovery distribution for Run LC5. A bar chart for Run LC6 is not presented because only a single slug was injected. For Runs LC4 (Figure 6.8) and LC5 there is no post-waterflood phase because a 20:1 water-oil ratio had been reached during the WAG process.

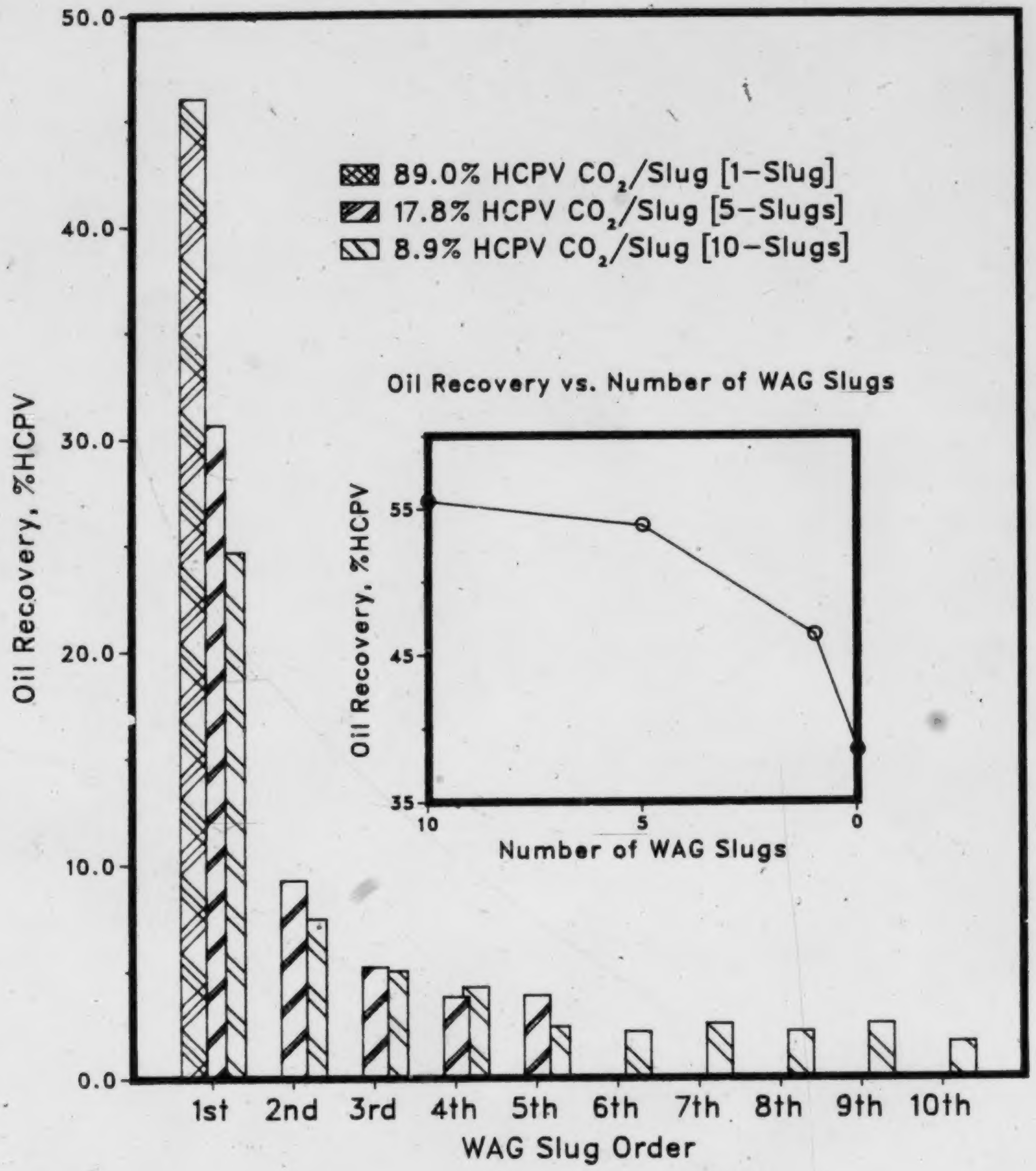
Figure 6.18 is a composite of the slug recovery distribution for Runs LC4, LC5, and LC6. Note the oil recovery decrease as the first slug size decreased. The plot of oil recovery versus number of WAG slugs (inset) indicates that a ten-slug distribution, of the same total carbon dioxide volume, recovered more oil (55.54%) than a five-slug (53.86%), a single-slug (46.37%) distribution, and the average waterflood recovery (38.51%). The incremental recovery of Run LC4 over LC5 is limited [≈2 percentiles], but the flood life was approximately 10% shorter.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 35.63 %, k = 10.800 darcies, S_o = 90.10 %, S_{wc} = 9.90 %

[0.89 HCPV CO2 @ 1.00 MPa (0.39 g-mol) 4:1 WAG, 5-Slugs]

Figure 6.17 Oil Recovery Distribution of Run LC 5.



Note: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
Water-Alternating-Gas (WAG) Process 4:1 WAG Ratio
Total CO_2 Injected = 0.89 HCPV (0.39 g-mol)

Figure 6.18 – Slug Recovery Distribution, Effect of Number of WAG Slugs

Figure 6.19 shows that the blowdown recovery increased dramatically with the number of WAG slugs. This is due to the increased presence of carbon dioxide during the latter stages of the flood, thus increasing the drive energy available during the blowdown phase. Figure 6.20 shows the effect of number of WAG slugs on carbon dioxide requirement and retention. The decrease in carbon dioxide requirement is due to additional oil recovery for the larger number of WAG slugs. The author feels the carbon dioxide retention depicted for the 5-slug run is too low due to problems associated with measuring produced gas. Previous investigations[15,22] have shown that high blowdown recovery corresponds to high carbon dioxide retention. The author feels that the present results confirm this finding.

The effect of the number of WAG slugs on oil recovery at 1.00 MPa is shown in Figure 6.21. Note the suppressed oil recovery in Run LC6 (1-slug) until the post-waterflood phase was implemented. Runs LC4 and LC5 appear to be similar but the bar chart (inset) shows the 10-slug process has a slightly higher initial slope and subsequently a more efficient displacement. Results from this work indicate that the optimum number of WAG slugs for the process is ten.

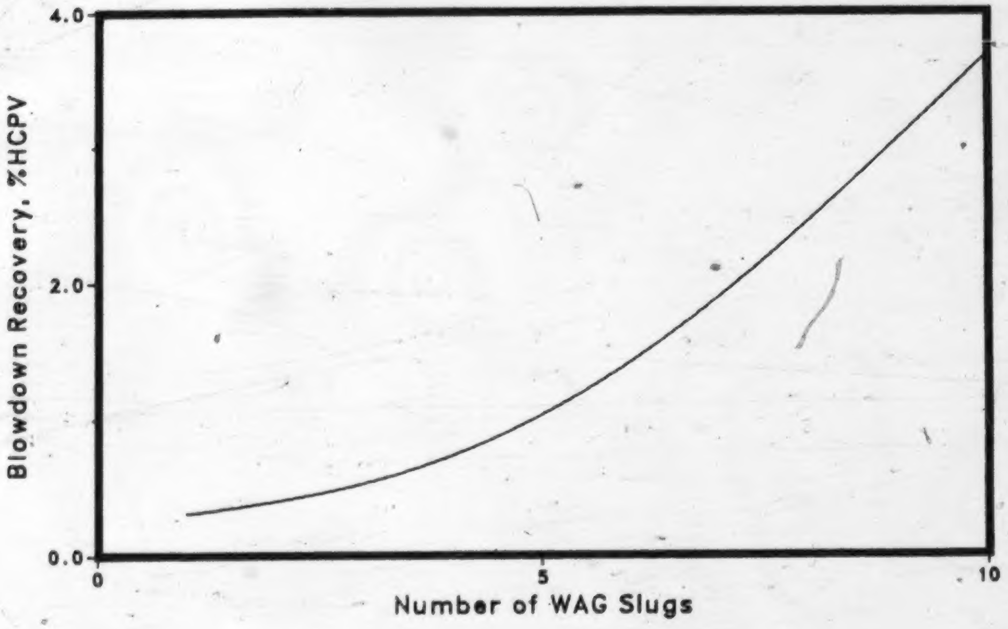


Figure 6.19 – Blowdown Recovery vs Number of WAG Slugs for the 4:1 WAG Process at 1.00 MPa

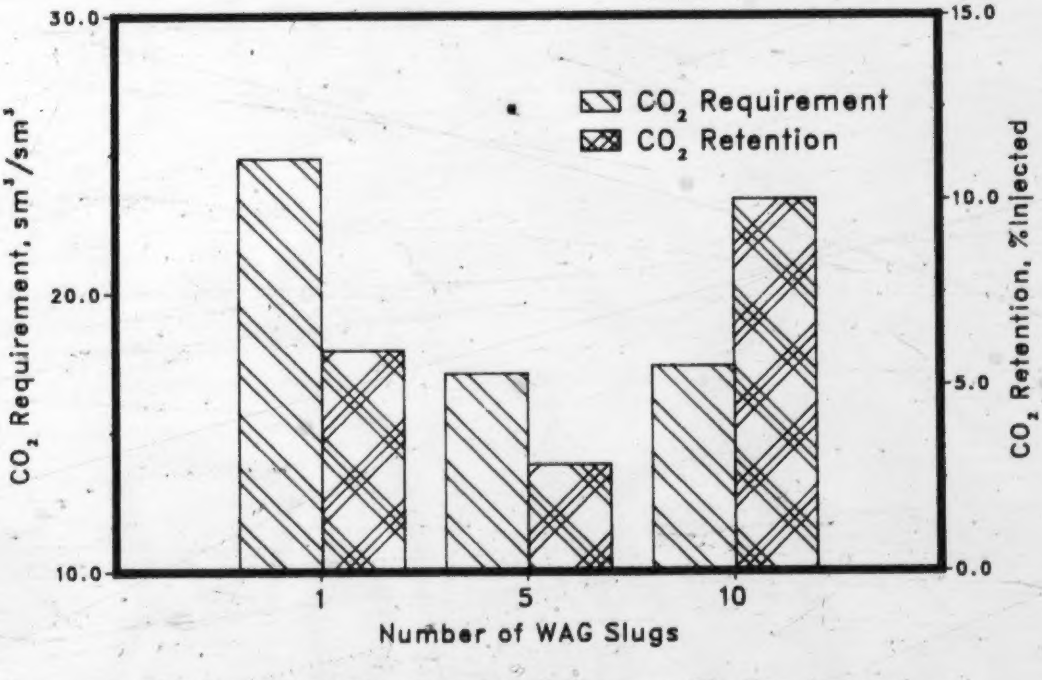


Figure 6.20 – Effect of Number of WAG Slugs on CO_2 Requirement and CO_2 Retention for the 4:1 WAG Process at 1.00 MPa.

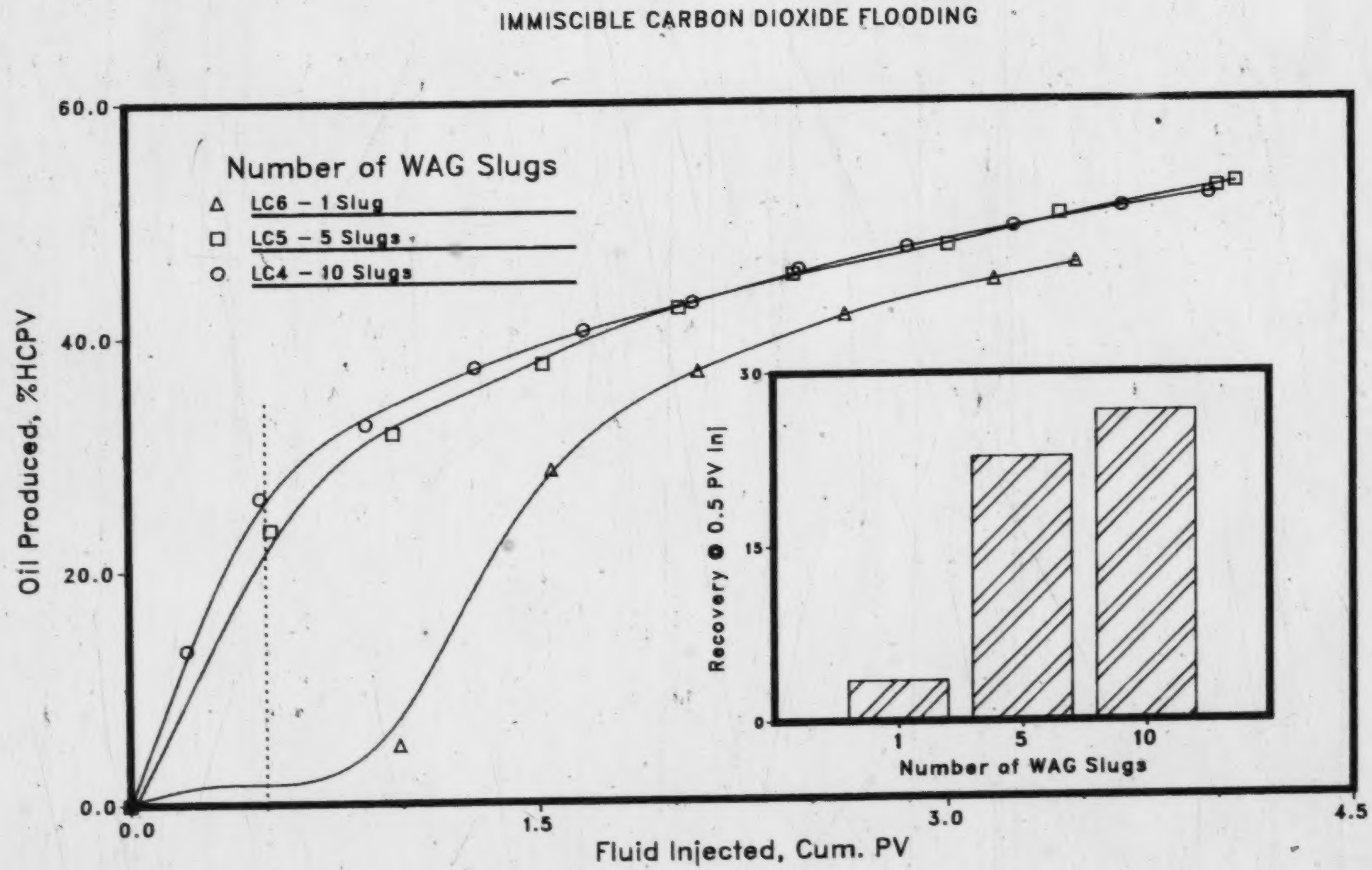


Figure 6.21 – Effect of Number of WAG Slugs on Oil Recovery at 1.00 MPa.

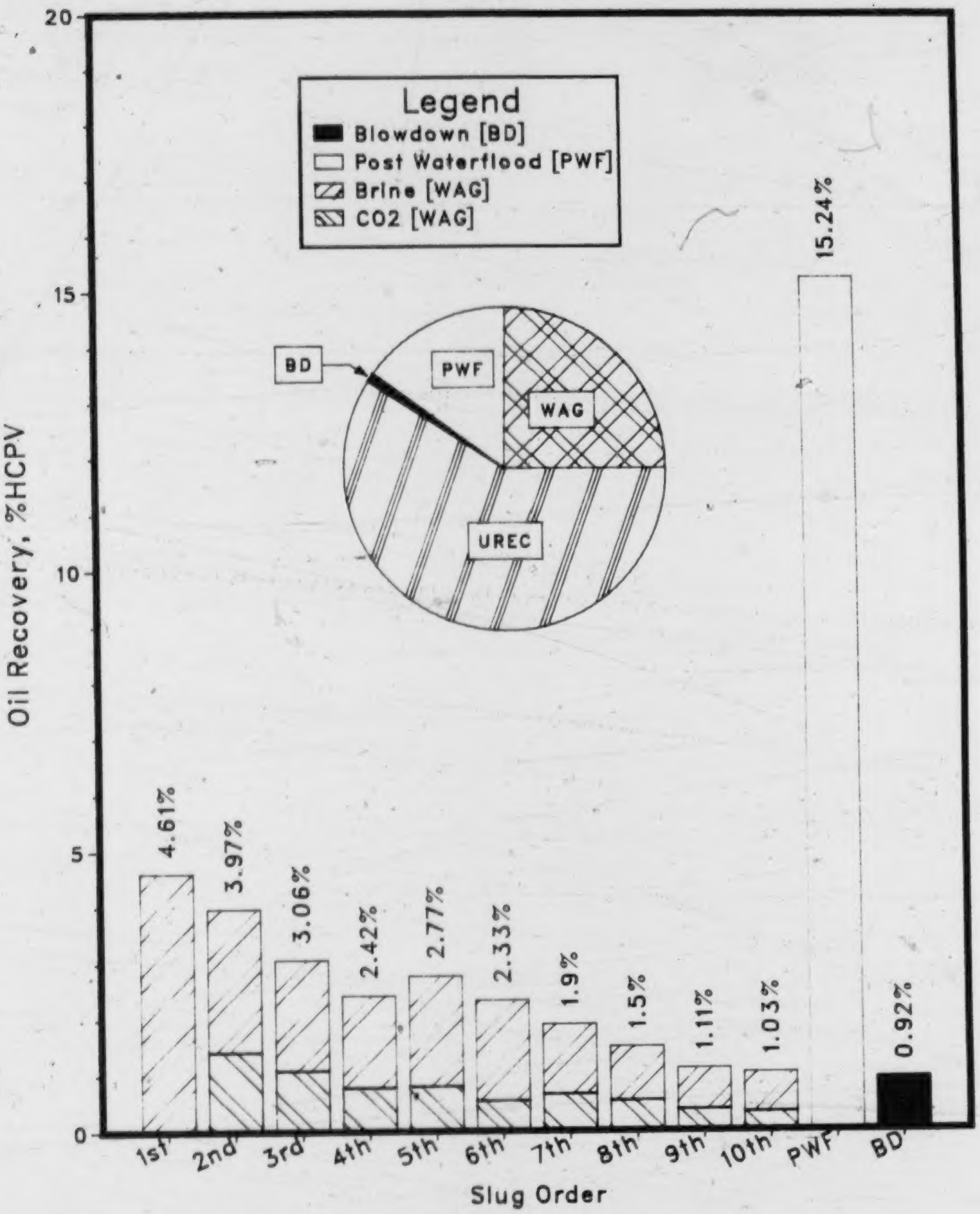
Effect of WAG Ratio and Velocity

Six runs at 1.00 MPa were conducted to determine the combined effect of WAG ratio and velocity on the immiscible carbon dioxide displacement process at low pressure. In all runs, an equal volume (mass) of carbon dioxide was injected, 0.20 HCPV at 1.00 MPa and 23°C (0.09 g-mol) utilizing 10 WAG slugs. Runs LC12, LC7, and LC11 were conducted at a velocity of 0.984 m/d with 2:1, 4:1, and 8:1 WAG ratios, respectively. Runs LC15, LC13, and LC14 were conducted at a velocity of 0.492 m/d (half the aforementioned) with the same three respective WAG ratios.

Figures 6.22 through 6.26 show the oil recovery distribution of Runs LC12, LC15, LC13, LC11, and LC14, respectively. The runs are grouped as pairs with the same WAG ratio but different flow velocities. Several interesting observations on the slug recovery distribution are:

1. As the WAG ratio increased, for both high and low velocities, the first slug oil recovery [CO_2+H_2O] increased and the post-waterflood recovery decreased. The dominance of first slug oil recovery and lack of post-waterflood at high WAG ratios was due to the relatively large volume of water injected in each WAG slug and subsequently, earlier flood-out (WOR ≥ 20:1).

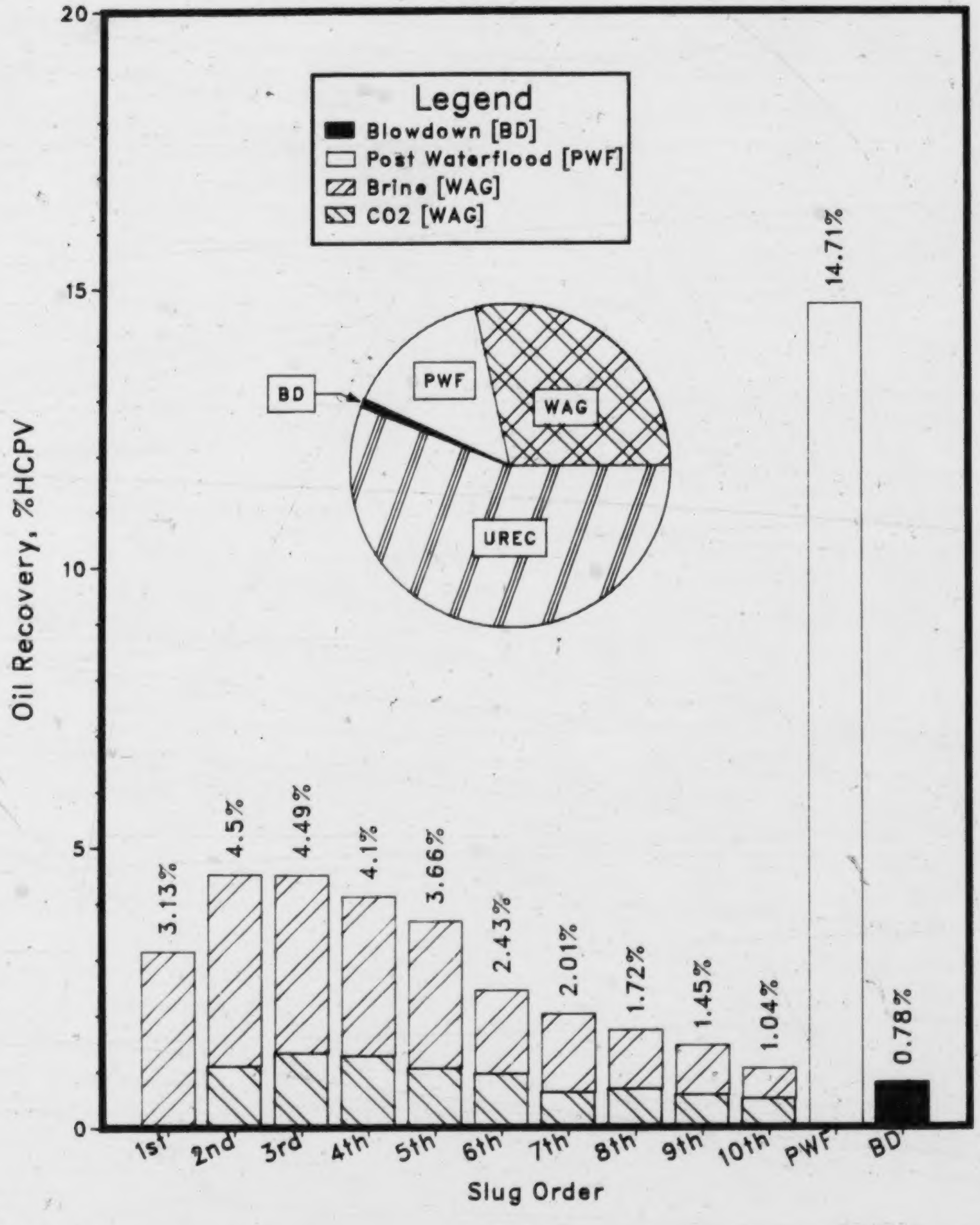
2. For all WAG ratios considered, the WAG process oil recovery increased with a reduction in velocity. However, the total oil recovery at intermediate and high WAG ratios increased with WAG ratio (see also Figure 6.30). At low velocity and low WAG ratio, the carbon dioxide contacts the oil for a longer period, and the water volume is smaller, thus allowing for less carbon dioxide dissolution in the water phase. Increased oil recovery for higher velocities may have been caused by a reduction in gravity segregation and the in-situ formation of a stabilizing emulsion at the flood front.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 38.40 %, k = 16.156 darcies, S_o = 90.84 %, S_{wc} = 9.16 %

[0.20 HCPV CO2 @ 1.00 MPa (0.09 g-mol) 2:1 WAG, 10-Slugs]

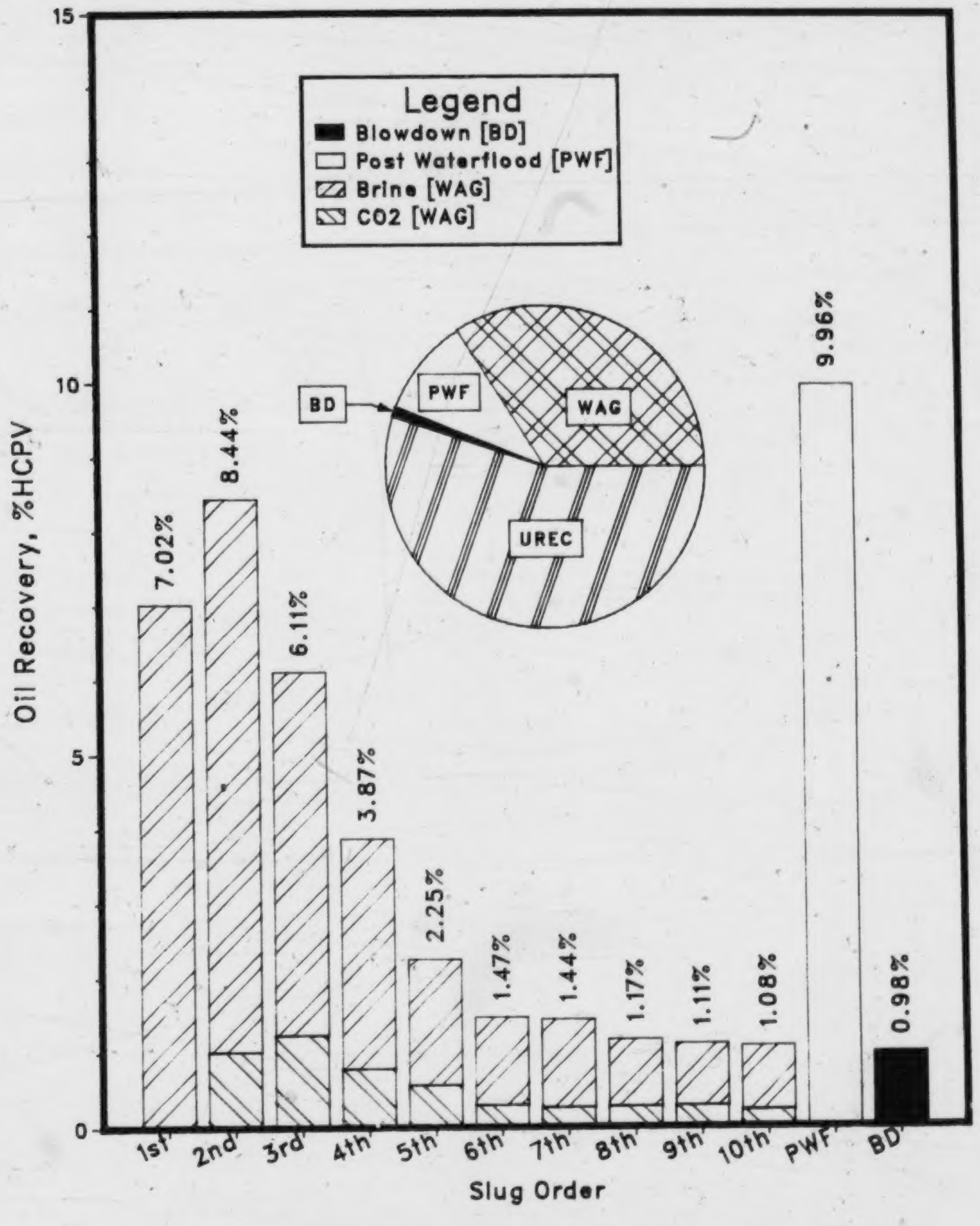
Figure 6.22 Oil Recovery Distribution of Run LC12.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.492 m/d, μ_o = 1055.3 mPa.s
ϕ = 36.57 %, k = 12.056 darcies, S_o = 90.28 %, S_{wc} = 9.72 %

[0.20 HCPV CO2 @ 1.00 MPa (0.09 g–mol) 2:1 WAG, 10–Slugs]

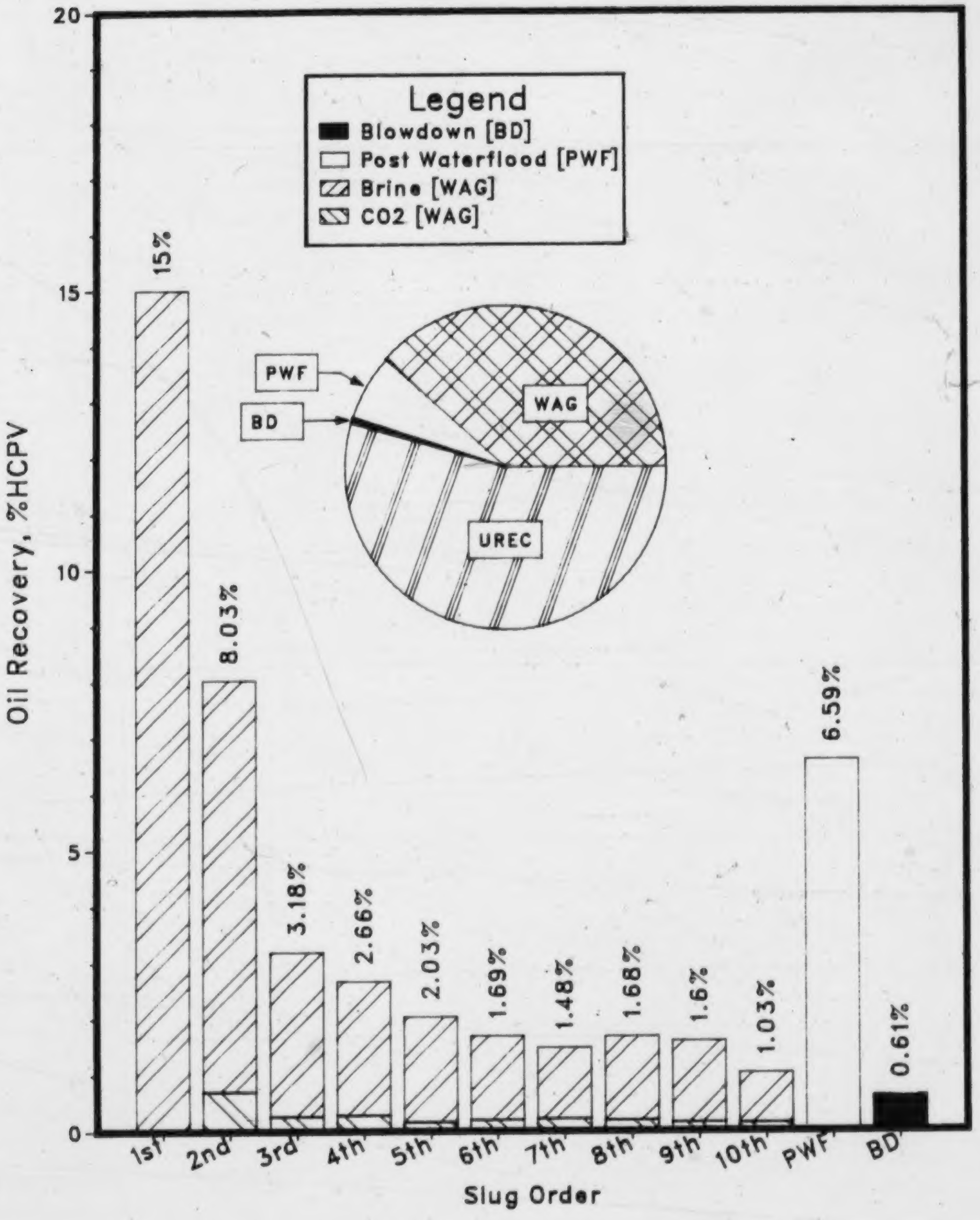
Figure 6.23 Oil Recovery Distribution of Run LC15.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.492 m/d, μ_o = 1055.3 mPa.s
ϕ = 36.22 %, k = 12.118 darcies, S_o = 90.51 %, S_{wc} = 9.49 %

[0.20 HCPV CO2 @ 1.00 MPa (0.09 g-mol) 4:1 WAG, 10-Slugs]

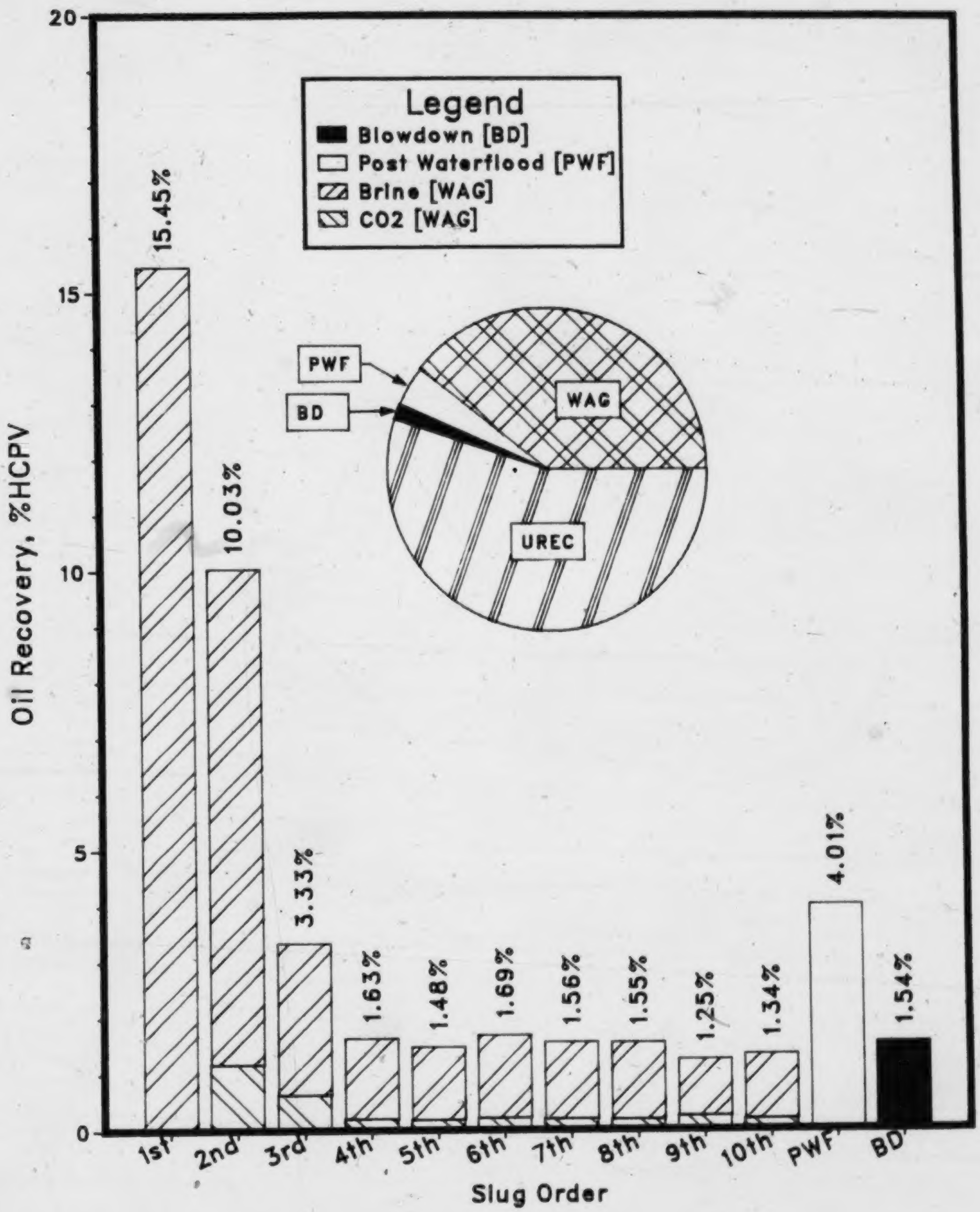
Figure 6.24 Oil Recovery Distribution of Run LC13.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 38.28 %, k = 13.998 darcies, S_o = 89.95 %, S_{wc} = 10.05 %

[0.20 HCPV CO2 @ 1.00 MPa (0.09 g-mol) 8:1 WAG, 10-Slugs]

Figure 6.25 Oil Recovery Distribution of Run LC11.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.492 m/d, μ_o = 1055.3 mPa.s
ϕ = 36.93 %, k = 12.047 darcies, S_o = 90.22 %, S_{wc} = 9.78 %

[0.20 HCPV CO2 @ 1.00 MPa (0.09 g-mol) 8:1 WAG, 10-Slugs]

Figure 6.26 Oil Recovery Distribution of Run LC14.

3. At a low WAG ratio, for both velocities, the slug recovery distribution tended to be more uniform, but overall oil recovery was low. As the WAG ratio increased, the earlier slugs tended to dominate the oil recovery during the WAG process, and the overall oil recovery was higher.

4. Blowdown recovery for the intermediate and high WAG ratios increased with a reduction in velocity. At the low WAG ratio, blowdown recovery was approximately the same for both velocities.

The oil-produced:fluid-injected ratio curves, Figures C.7 and C.11 through C.15, indicate that at low WAG ratios, the volume of water injected between carbon dioxide slugs was not large enough to eliminate the oil production delay generated by the carbon dioxide gas. At the higher WAG ratios the flood life was considerably shorter resulting in lower oil recovery. Note also the reduction in oil-produced:fluid-injected ratio during the injection of carbon dioxide gas.

Figures 6.27 and 6.28 show the effect of WAG ratio and velocity on the cumulative gas-oil ratio and cumulative water-oil ratio, respectively. Low cumulative gas-oil and water-oil ratios reduce fluid handling costs of a field project and are also indicative of mobility control of the displacing fluids.

Figure 6.27 shows the cumulative gas-oil ratio curves for Runs LC7, and LC11 through LC15. The banded areas represent the trend of increasing cumulative gas-oil ratio at higher flow velocities. Carbon dioxide breakthrough occurred earlier at higher injection rates; creating flow channel(s) between the injection and production wells and subsequent high gas production rates. The cumulative gas-oil ratio appears to be insensitive to the WAG ratio. This is to be expected because the volume of carbon dioxide injected in all runs is constant and unaffected by the WAG ratio.

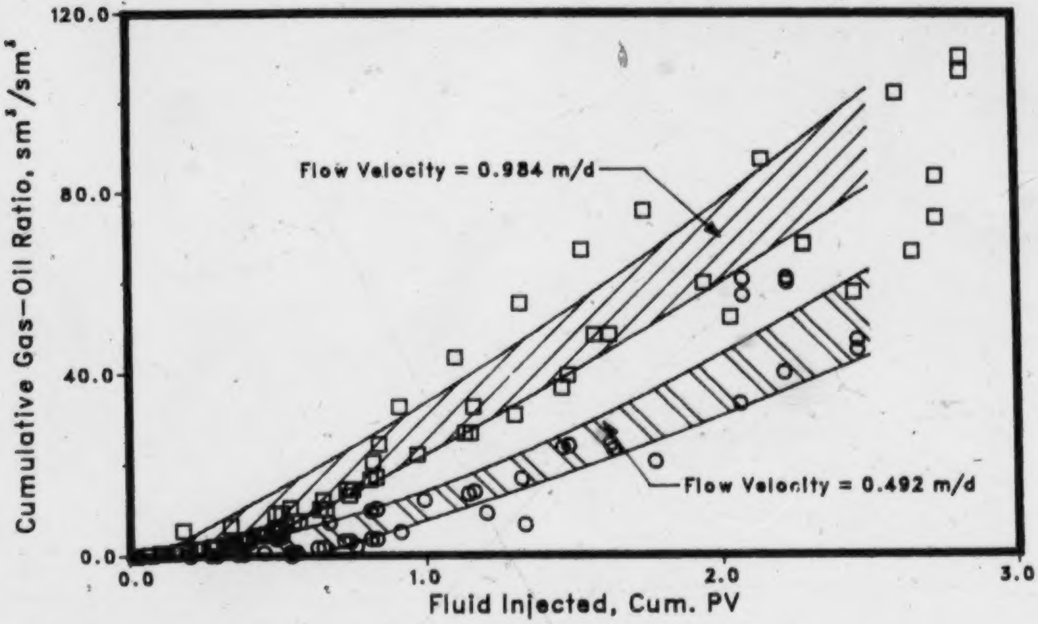


Figure 6.27 – Effect of WAG Ratio and Velocity on Cumulative Gas-Oil Ratio at 1.00 MPa.

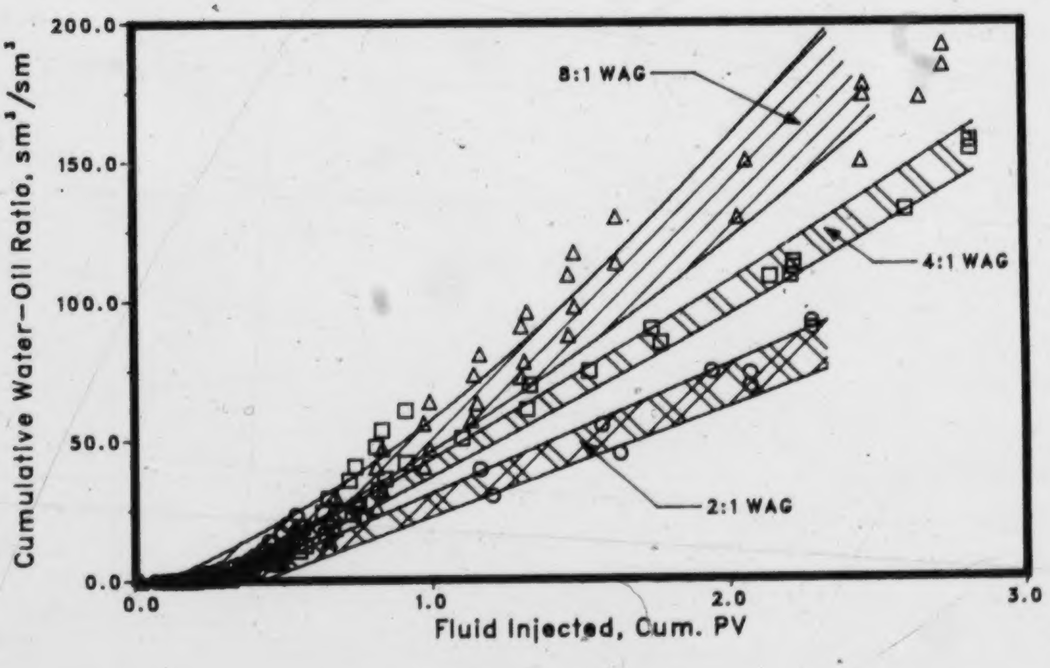


Figure 6.28 – Effect of WAG Ratio and Velocity on Cumulative Water-Oil Ratio at 1.00 MPa

Figure 6.28 shows the cumulative water-oil ratio for the same six runs. Contrary to the trend of the cumulative gas-oil ratio curves, the cumulative water-oil ratio curves appear to be insensitive to velocity. The data shows a trend of increasing cumulative water-oil ratio at higher WAG ratios. This is to be expected due to the much larger volumes of water injected at higher WAG ratios.

Figure 6.29 illustrates another interesting trend shown by varying the WAG ratio and flow velocity. Although the carbon dioxide requirement was approximately the same for all runs (5.1 sm^3/sm^3) the carbon dioxide retention varied considerably. At high flow velocities the carbon dioxide retention decreased while at low flow velocities, the opposite occurred. This odd occurrence may be explained as follows. For the lower flow velocity, carbon dioxide gas contacts the oil for a longer period of time, thus allowing more carbon dioxide to dissolve in the oil. This is further substantiated by the larger blowdown recoveries for the low velocity runs (Table 6.1) associated with high carbon dioxide retention. At the higher flow velocities carbon dioxide gas fingers more rapidly. Therefore a smaller portion of the oil is contacted by the gas leading to less carbon dioxide dissolving in the oil and a smaller free gas phase.

Figure 6.30 summarizes the overall oil recoveries at different WAG ratios. The points corresponding to an infinite [∞] WAG ratio are for the two waterflood runs (LC1 and LC2). It can be seen that the 4:1 WAG ratio was optimal for both velocities because more oil was produced for the same volume of carbon dioxide injected. Figure 6.31 also suggests that the 4:1 WAG process is the optimum. The bar chart (inset) shows that although the lower velocity runs had higher initial slopes, the 4:1 WAG process at high velocity had an initial slope nearly equal to that of the 8:1 WAG process, at high velocity, and recovered the most oil (46.97% HCPV).

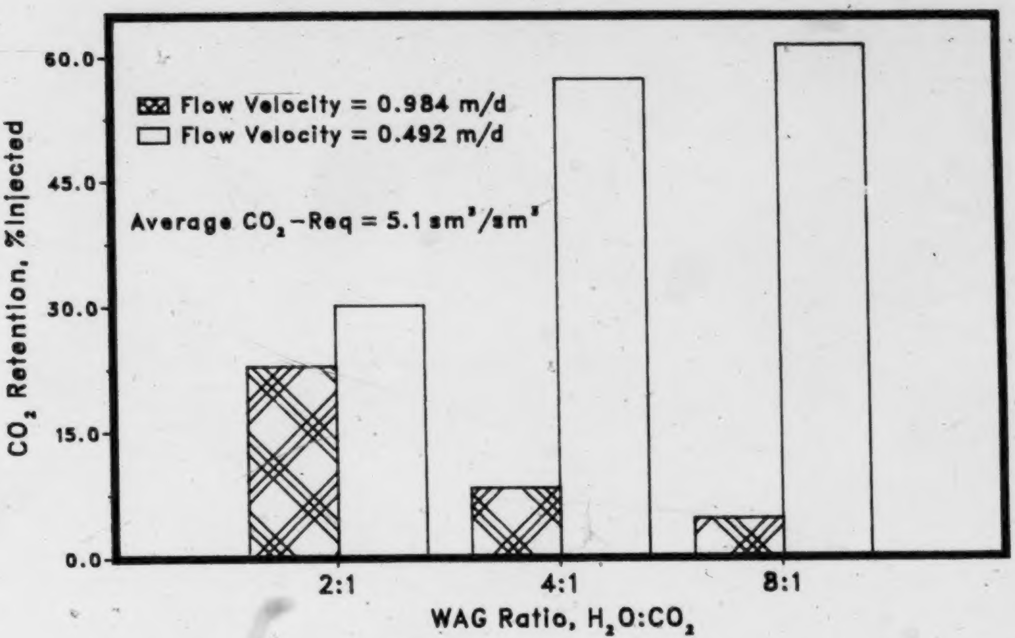


Figure 6.29 – Effect of WAG Ratio on CO_2 Retention at Constant Velocity and CO_2 Volume = 20% HCPV.

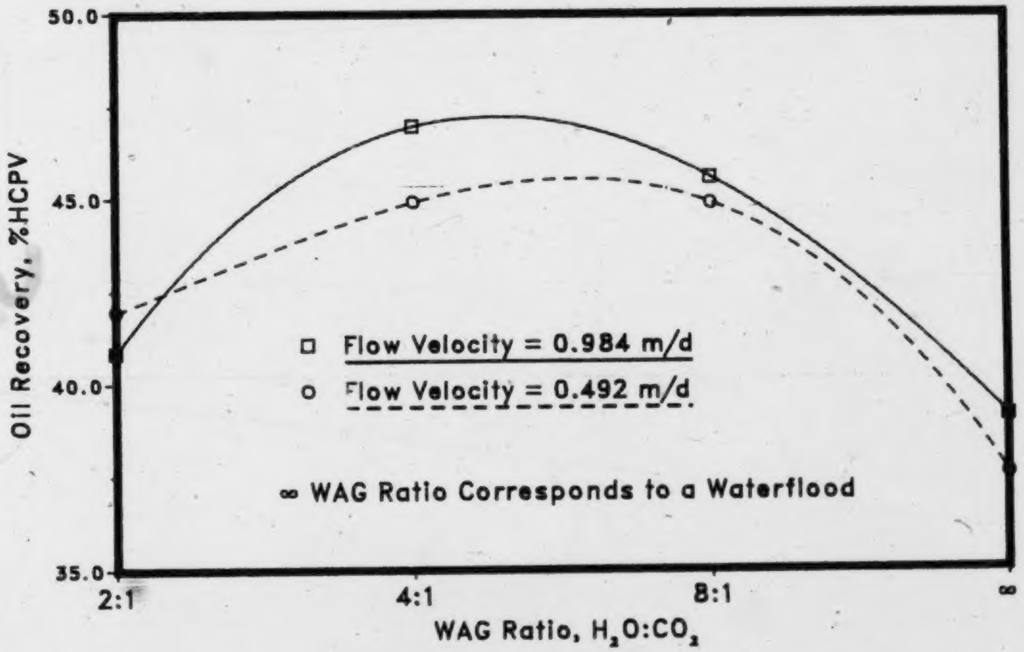


Figure 6.30 – WAG Ratio vs. Total Oil Recovery at Constant Velocity and CO_2 Volume = 20% HCPV.

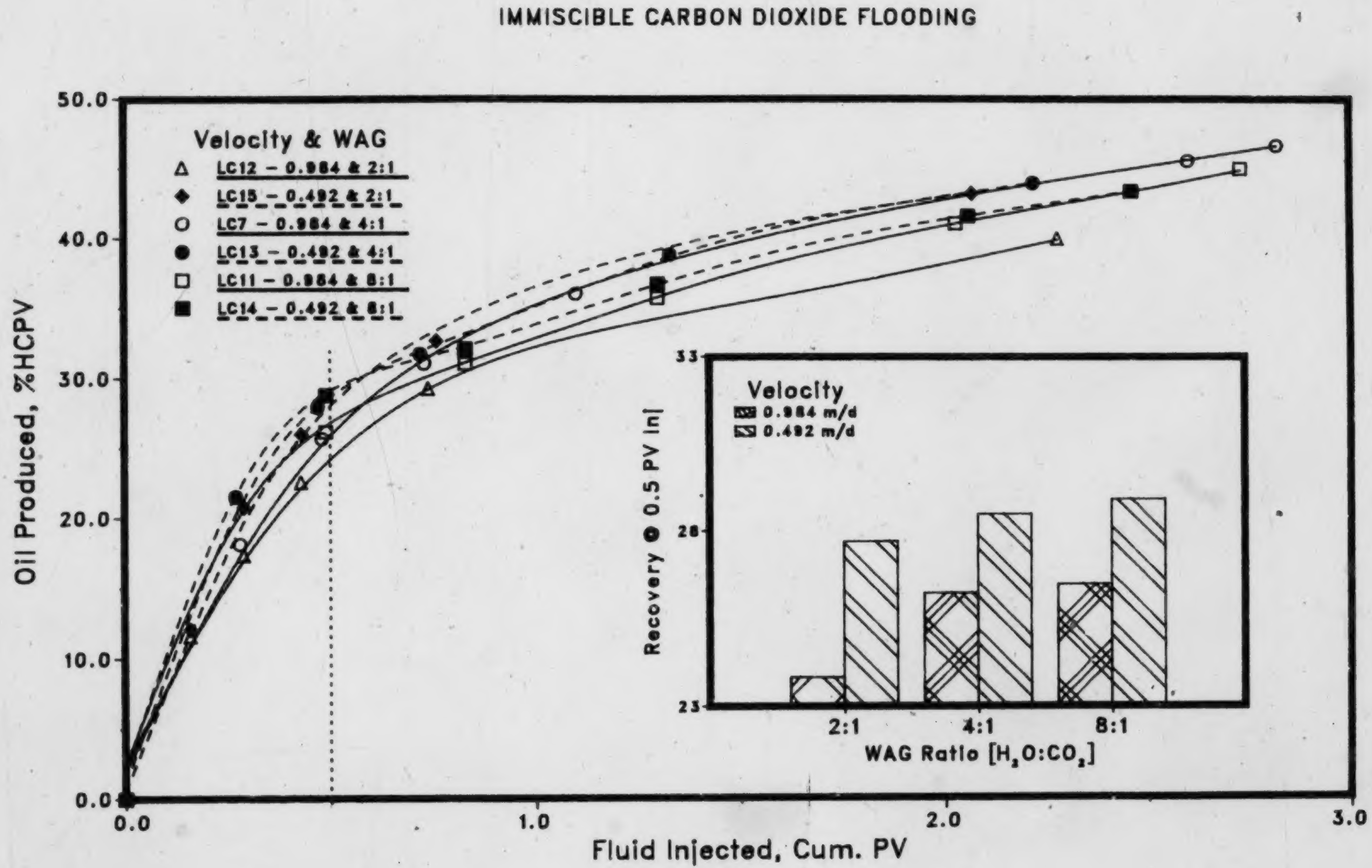


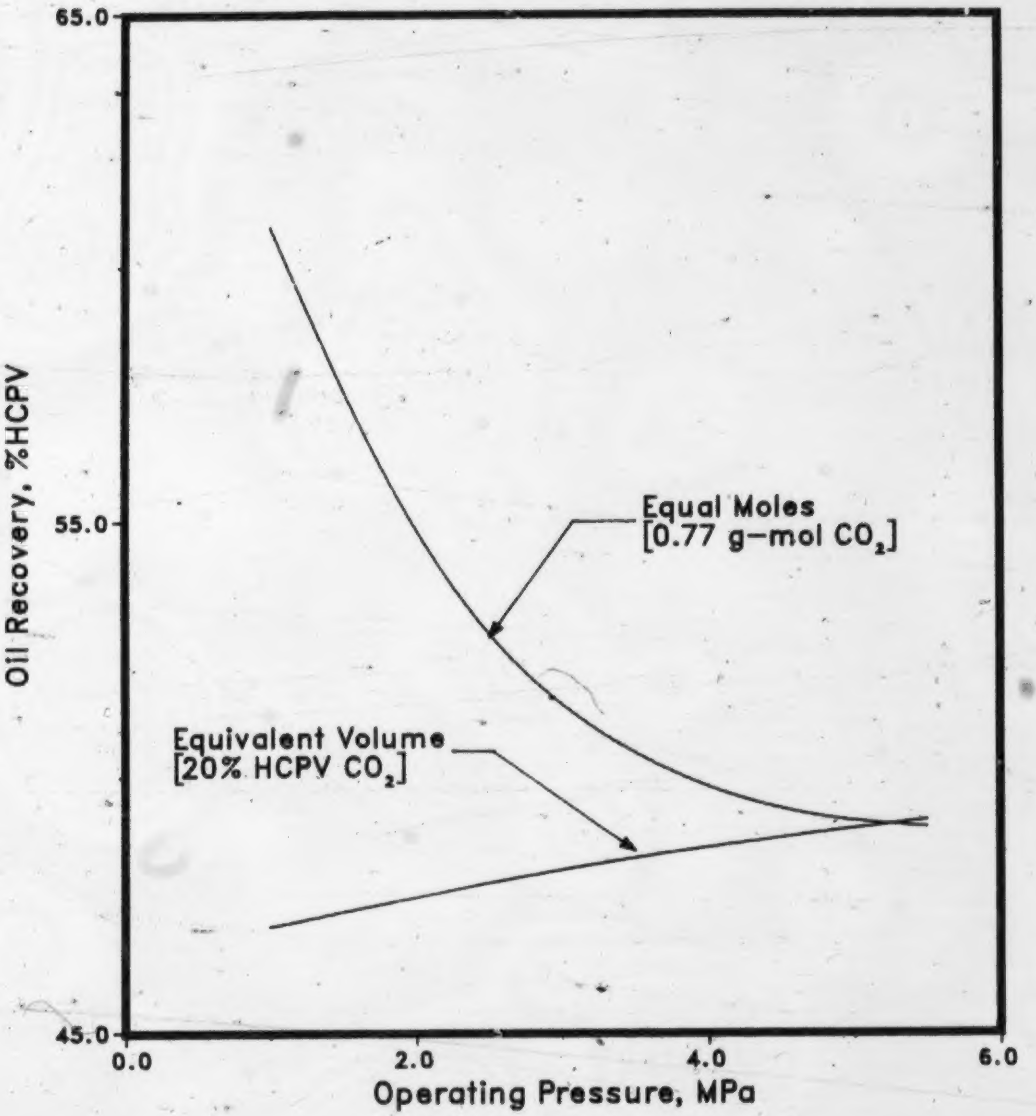
Figure 6.31 – Effect of WAG Ratio and Velocity on Oil Recovery at 1.00 MPa.

Effect of Operating Pressure

Subcritical carbon dioxide is a highly compressible fluid. Figure 3.2 shows the wide range of volumes subcritical carbon dioxide occupies at 20.6°C under various pressures. Subsequently, a problem arises when comparing the amount of carbon dioxide gas injected at different pressures. For this reason, the amount of carbon dioxide injected is presented as both the volume at the prevailing model conditions of pressure and temperature (HCPV) called "equivalent volume" hereinafter, as well as the number of moles (g-mol), which is an absolute measurement of amount of substance.

Figure 6.32 illustrates the drastic difference in total oil recovery, for the 4:1 WAG process, when comparing an equal volume or an equal number of moles of carbon dioxide injected at various pressures. The intersection point at 5.50 MPa represents where a 20% HCPV CO_2 slug is equivalent to a 0.77 g-mol slug. For the case of equal moles of carbon dioxide injected, oil recovery dropped dramatically at increased pressures, while for the case of an equivalent volume of carbon dioxide injected, oil recovery increased slightly. Therefore the process is dependent on the carbon dioxide surface contact, viz. a function of the volume of carbon dioxide at reservoir conditions. Thus it is very important to be precise in describing the amount of carbon dioxide injected.

Runs LC3, LC16, and LC20 (Figures 6.11, 6.33, 6.34, respectively) utilized an equal total number of moles of carbon dioxide [0.77 g-mol] injected, while Runs LC7, LC17, and LC20 (Figures 6.8, 6.35, 6.34 respectively) utilized an equal total volume of carbon dioxide [0.20 HCPV] injected. Figure 6.36 is the slug recovery distribution for a 10% slug of carbon dioxide at 5.50 MPa. Note for the case of equal moles injected, the first slug [CO_2+H_2O] oil recovery dropped dramatically with pressure while for the equal volume case, the first slug oil recovery increased slightly with pressure. This correlates very well with total oil recovery (see Figure 6.32), and emphasizes the importance of the first slug oil recovery.



Note: Average Run Conditions: Direct Line Drive, and 23°C
Model Parameters: Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
Water–Alternating–Gas (WAG) Process, 4:1 WAG Ratio

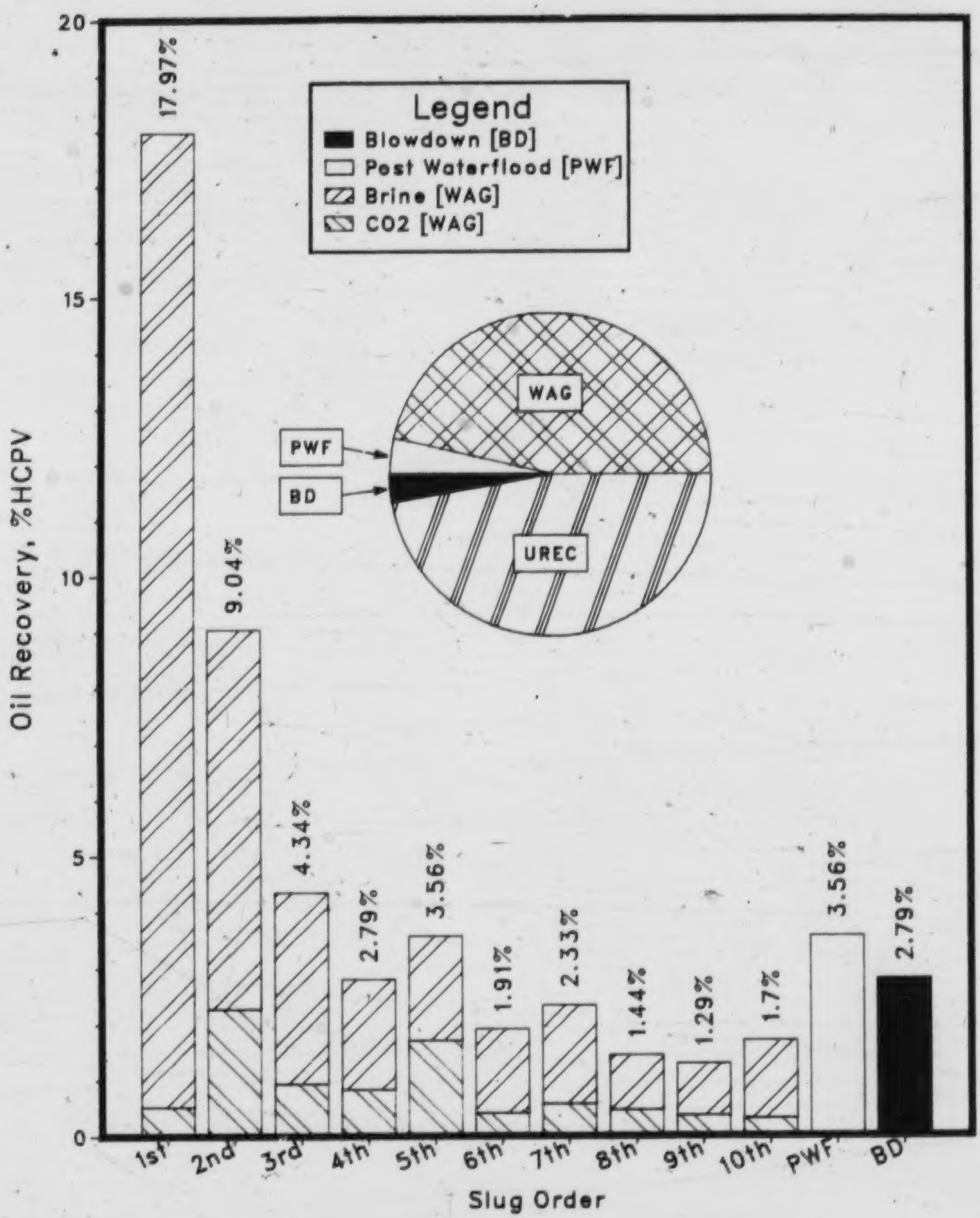
Figure 6.32 – Total Oil Recovery vs. Amount of Carbon Dioxide Injected.

Figure 6.37 shows the effect of total oil recovery, for constant total carbon dioxide slug size (volume basis), at various pressures. Only a single point was available for the 40%-slug, therefore an extrapolated curve similar to that of the 10%-slug was drawn. As can be seen, total oil recovery increased with total carbon dioxide slug size, as shown earlier, and also increased with pressure. The increase in oil recovery with pressure is most likely due to the additional mixing of carbon dioxide with the heavy oil at elevated pressures. The solubility of carbon dioxide in Lloydminster Aberfeldy [15°API] oil at 1.00 MPa is approximately 10 sm^3/sm^3, while at 5.5 MPa it is approximately 70 sm^3/sm^3, a 600% increase. The dashed curve of Figure 6.37 shows the carbon dioxide-oil solubility curve for the Aberfeldy oil. There does not seem to be a strong correlation between oil recovery and solubility although a general increasing trend is apparent.

Figure 6.38 compares the oil recovery curves (20% HCPV CO_2) at pressures of 1.00, 2.50, and 5.50 MPa. It is readily seen that the curves differ slightly throughout the producing life. The initial slope of the 5.50 MPa displacement is higher (bar chart inset) because at the higher operating pressures the injected carbon dioxide is more viscous. Thus at higher pressures, a liquid-liquid type displacement occurred rather than a gas-liquid type displacement, leading to a more favorable mobility ratio.

Operating pressure had a tremendous effect on the carbon dioxide requirement and retention. As the pressure increased, both carbon dioxide requirement and retention increased due to increased solubility. Table 6.3 illustrates the increases for Runs LC7, LC17, and LC20, where an equivalent volume of carbon dioxide was injected in all runs. The modified carbon dioxide requirement [Mod-Req] reflects the amount of carbon dioxide that was actually utilized during the displacement. It is seen from Table 6.3 that the modified carbon dioxide requirements were approximately of the same order of magnitude.

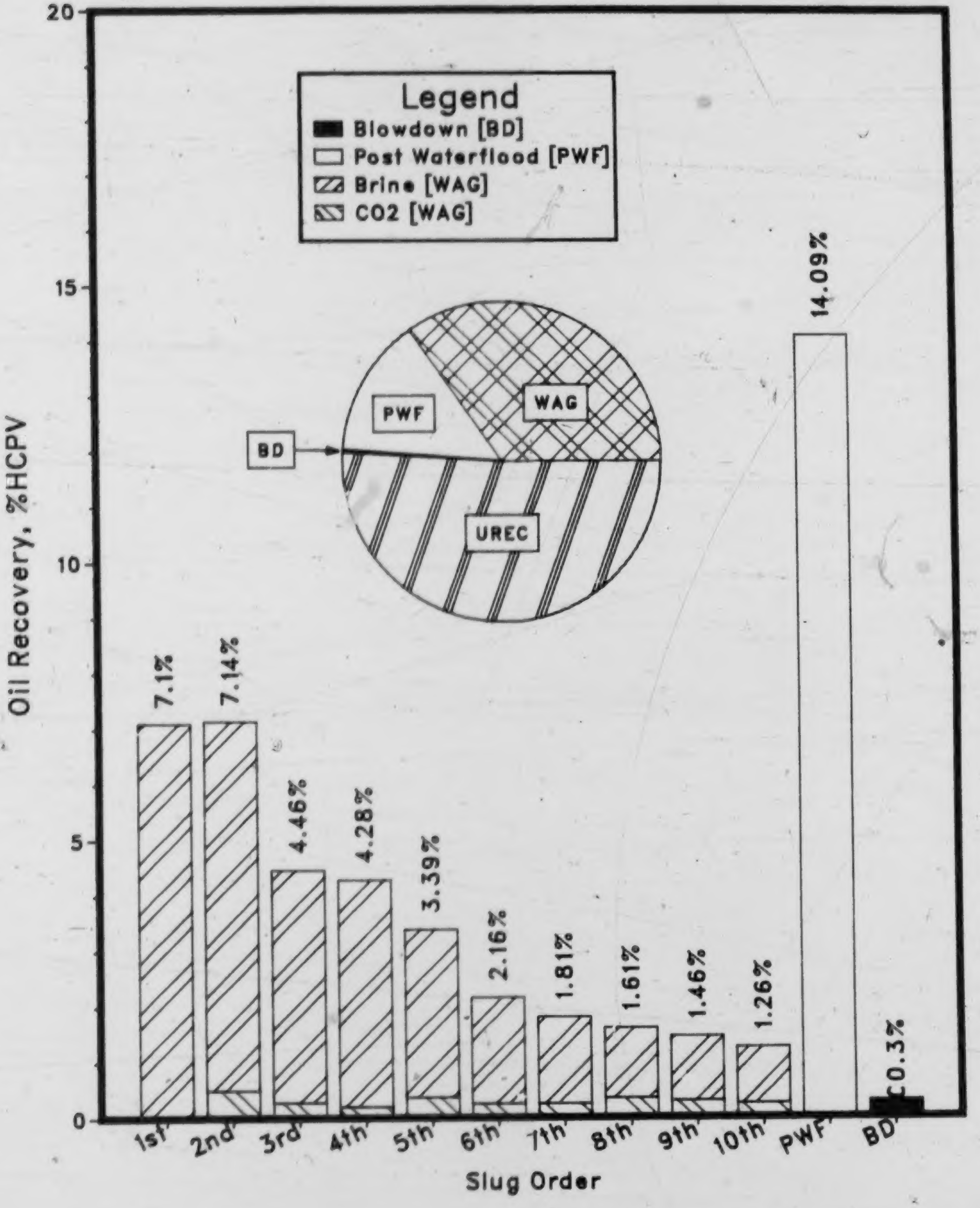
Although the effect of operating pressure did not have a significant effect on total oil recovery, it is important to note that the



NOTE: Average Run Conditions: Direct Line Drive, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1059.0 mPa.s
ϕ = 34.77 %, k = 9.025 darcies, S_o = 79.11 %, S_{wc} = 20.89 %

[0.64 HCPV CO2 @ 2.50 MPa (0.77 g-mol) 4:1 WAG, 10-Slugs]

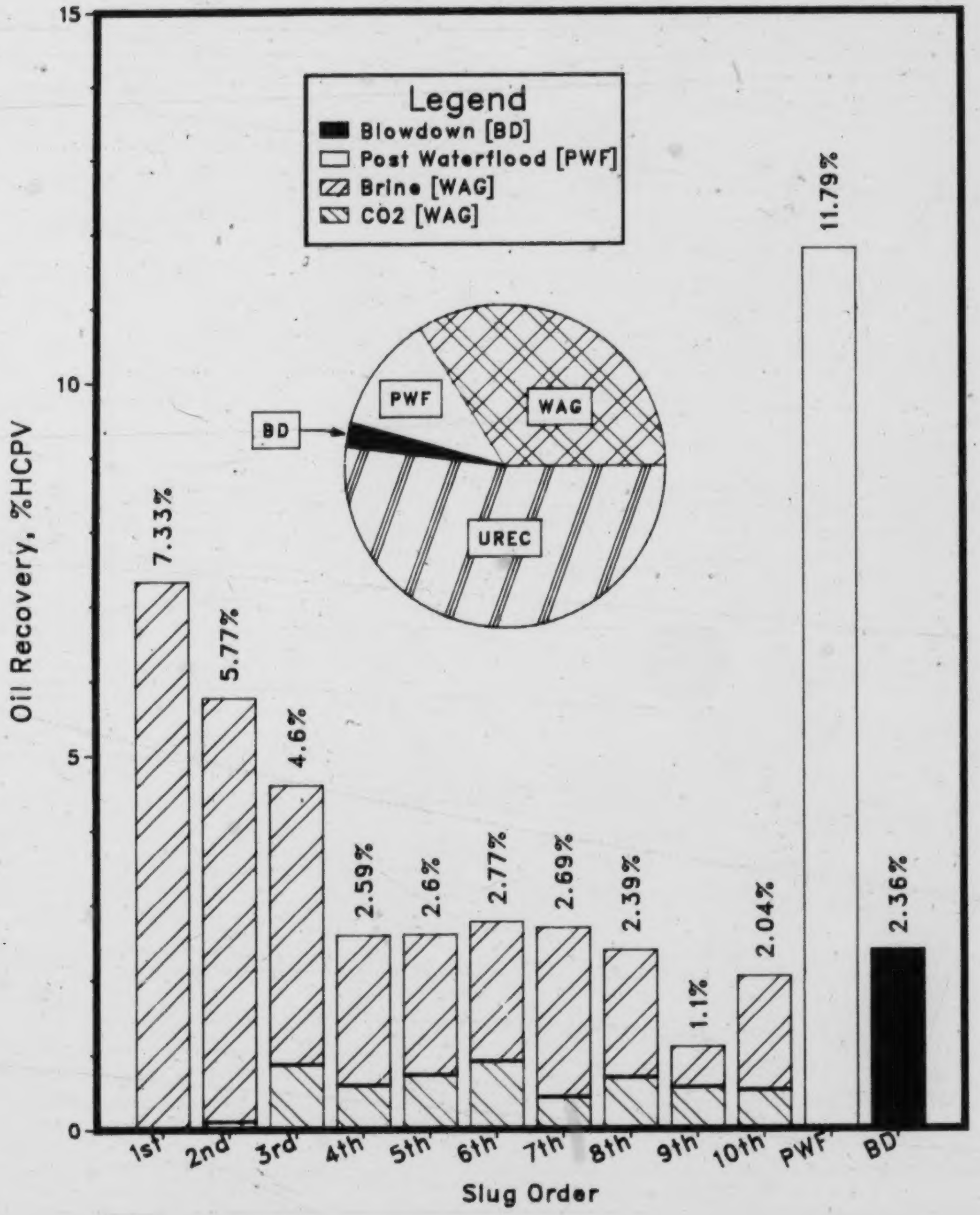
Figure 6.33 – Oil Recovery Distribution of Run LC16.



NOTE: Average Run Conditions: Direct Line Drive, 5.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 35.77 %, k = 12.451 darcies, S_o = 89.34 %, S_{wc} = 10.66 %

[0.20 HCPV CO2 @ 5.50 MPa (0.77 g-mol) 4:1 WAG, 10-Slugs]

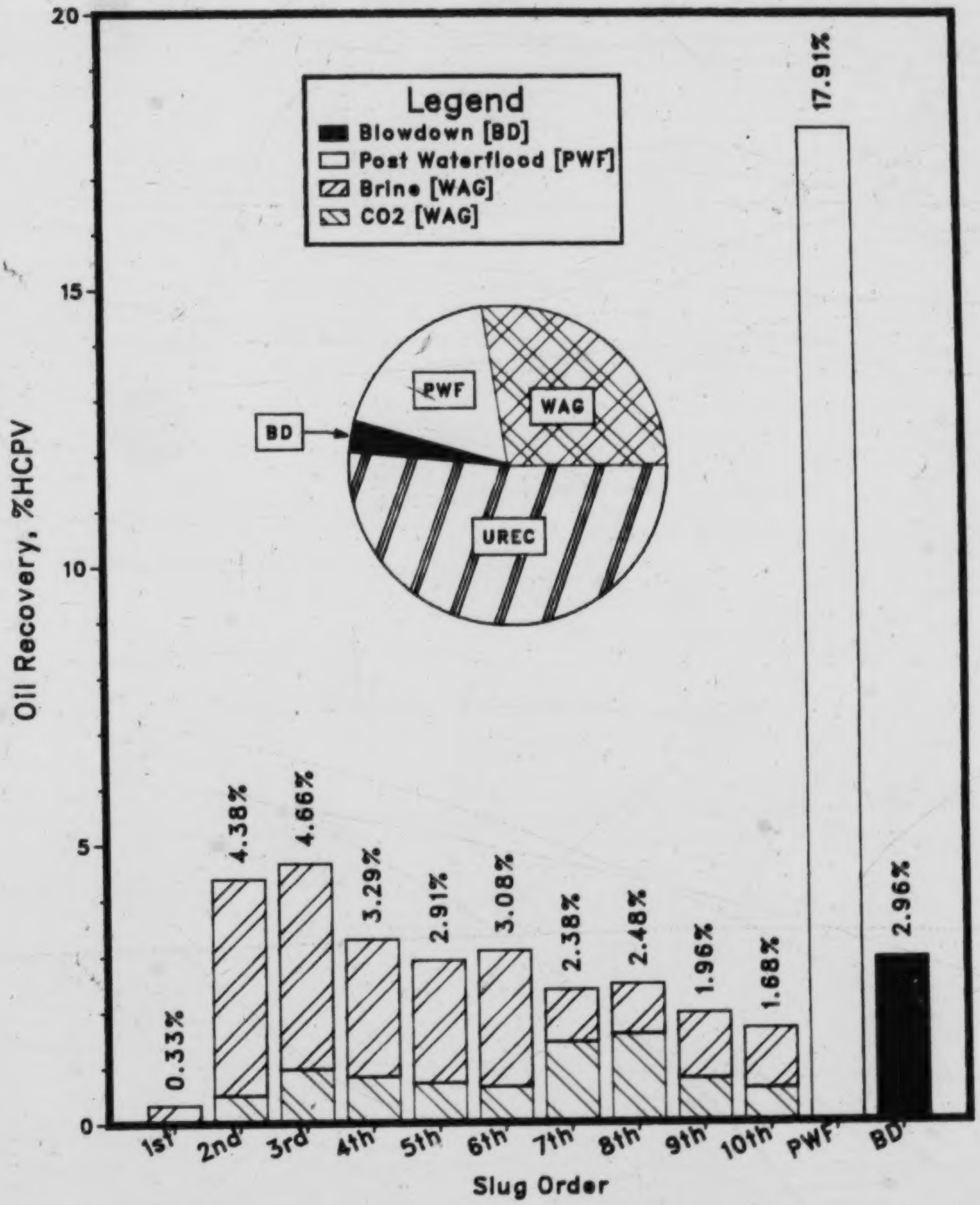
Figure 6.34 – Oil Recovery Distribution of Run LC20.



NOTE: Average Run Conditions: Direct Line Drive, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 37.70 %, k = 12.304 darcies, S_o = 89.16 %, S_{wc} = 10.84 %

[0.20 HCPV CO2 @ 2.50 MPa (0.26 g-mol) 4:1 WAG, 10-Slugs]

Figure 6.35 Oil Recovery Distribution of Run LC17.



NOTE: Average Run Conditions: Direct Line Drive, 5.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 36.69 %, k = 15.095 darcies, S_o = 93.95 %, S_{wc} = 6.05 %

[0.10 HCPV CO2 @ 5.50 MPa (0.42 g-mol) 4:1 WAG, 10-Slugs]

Figure 6.36 – Oil Recovery Distribution of Run LC21.

in-situ carbon dioxide utilization [ISUF], at prevailing conditions, declined with increasing pressure (see Table 6.3). It is also important to note that additional oil was recovered by the carbon dioxide flooding process at pressures well below the theoretical minimum miscibility pressure [MMP] for heavy oil systems (> 27.6 MPa for Aberfeldy)[22].

Table 6.3

Effect of Operating Pressure on CO_2 Requirement and Retention

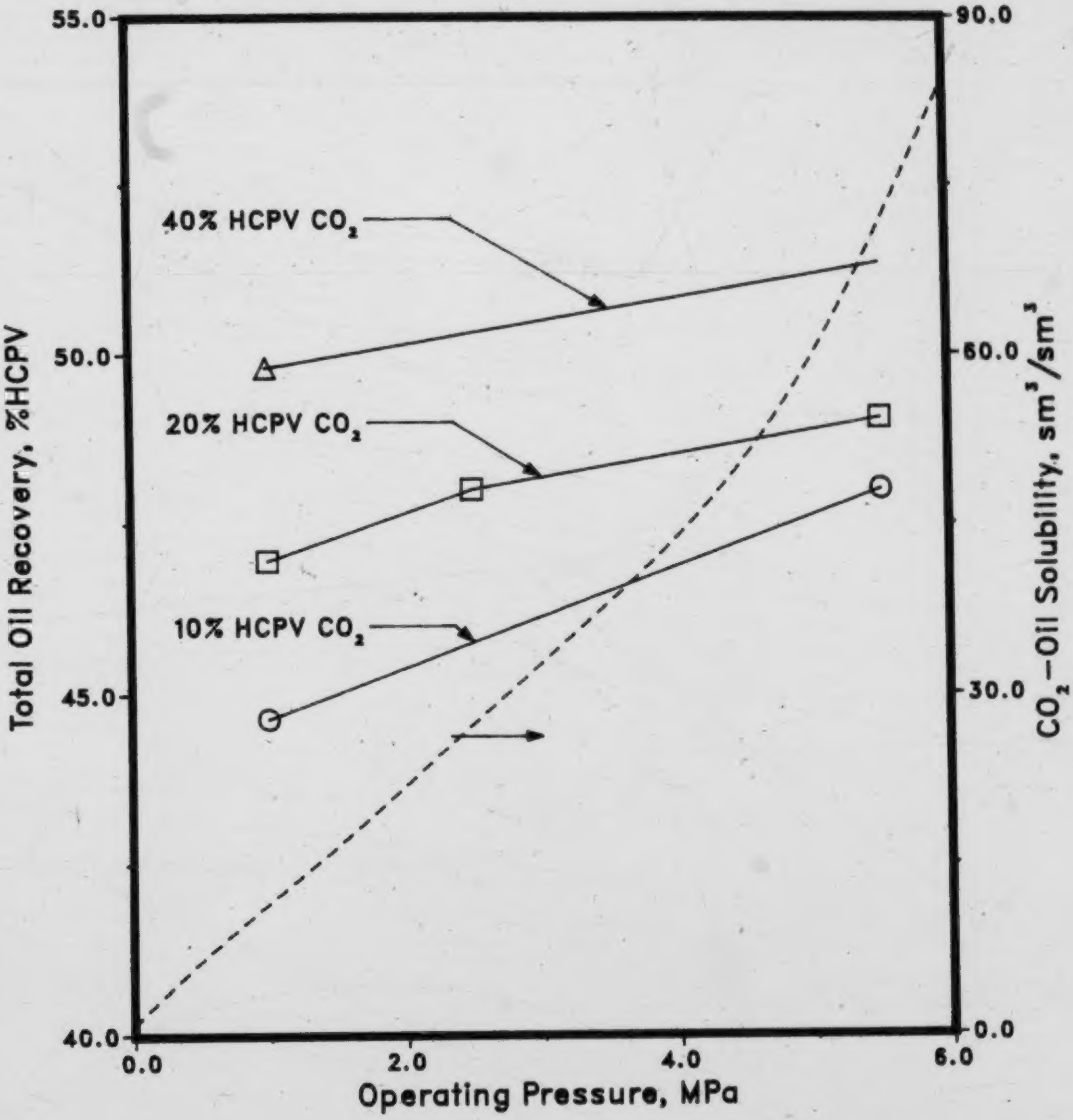
Run	Operating	Oil	Carbon Dioxide Inj		Carbon Dioxide			
LC #	Pressure	Recovery	Vol	Moles	Ret	Req *	Mod -Req†	ISUF¥
–	[MPa]	[%HCPV]	[%HCPV]	[g-mol]	[%Inj]	[sm^3/sm^3]	[sm^3/sm^3]	--
7	1.00	46.97	20.0	0.09	8.37	4.44	4.07	0.426
17	2.50	48.02	20.0	0.26	20.46	12.64	10.05	0.416
20	5.50	49.02	20.0	0.77	80.04	37.76	7.54	0.408

* $\text{Req} = \frac{\text{Vol } CO_2 \text{ Injected}}{\text{Volume Oil Produced}}$ @ STP — Carbon Dioxide Requirement

† $\text{Mod-Req} = \text{Req} \bullet \frac{(100 - \%\text{Ret})}{100}$ — Modified Carbon Dioxide Requirement

¥ $\text{ISUF} = \frac{\text{HCPV } CO_2 \text{ Injected}}{\text{HCPV Oil Produced}}$ — In-Situ Carbon Dioxide Utilization Factor

IMMISCIBLE CARBON DIOXIDE FLOODING



Note: Average Run Conditions: Direct Line Drive, and 23°C
Model Parameters: Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
Water-Alternating-Gas (WAG) Process, 4:1 WAG Ratio

Figure 6.37 – Total Oil Recovery vs. Operating Pressure for 10%, 20%, and 40% HCPV CO_2 Slugs.

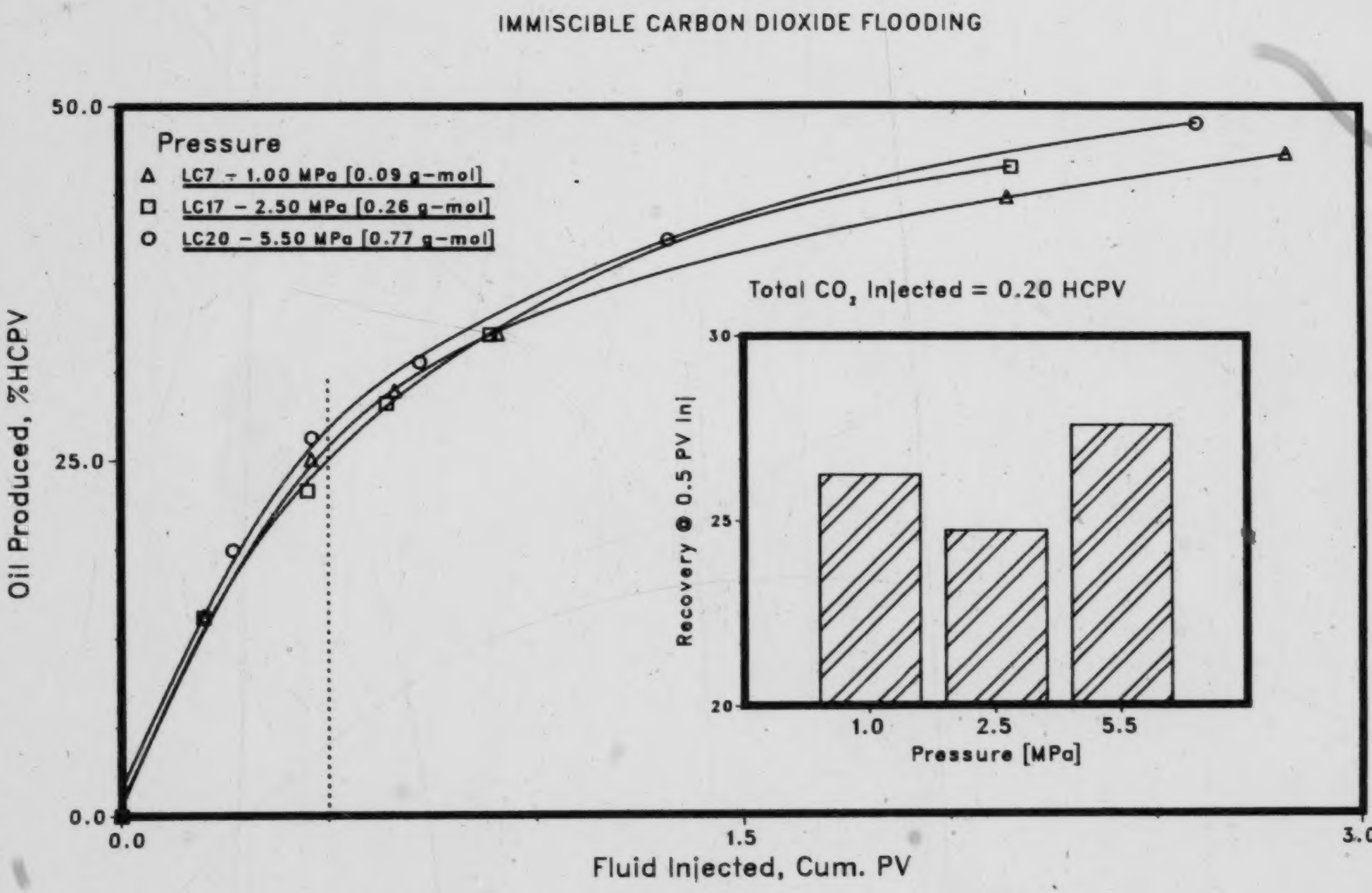


Figure 6.38 – Effect of Operating Pressure on Oil Recovery at 1.0, 2.5, and 5.5 MPa.

Effect of Initial Oil Viscosity

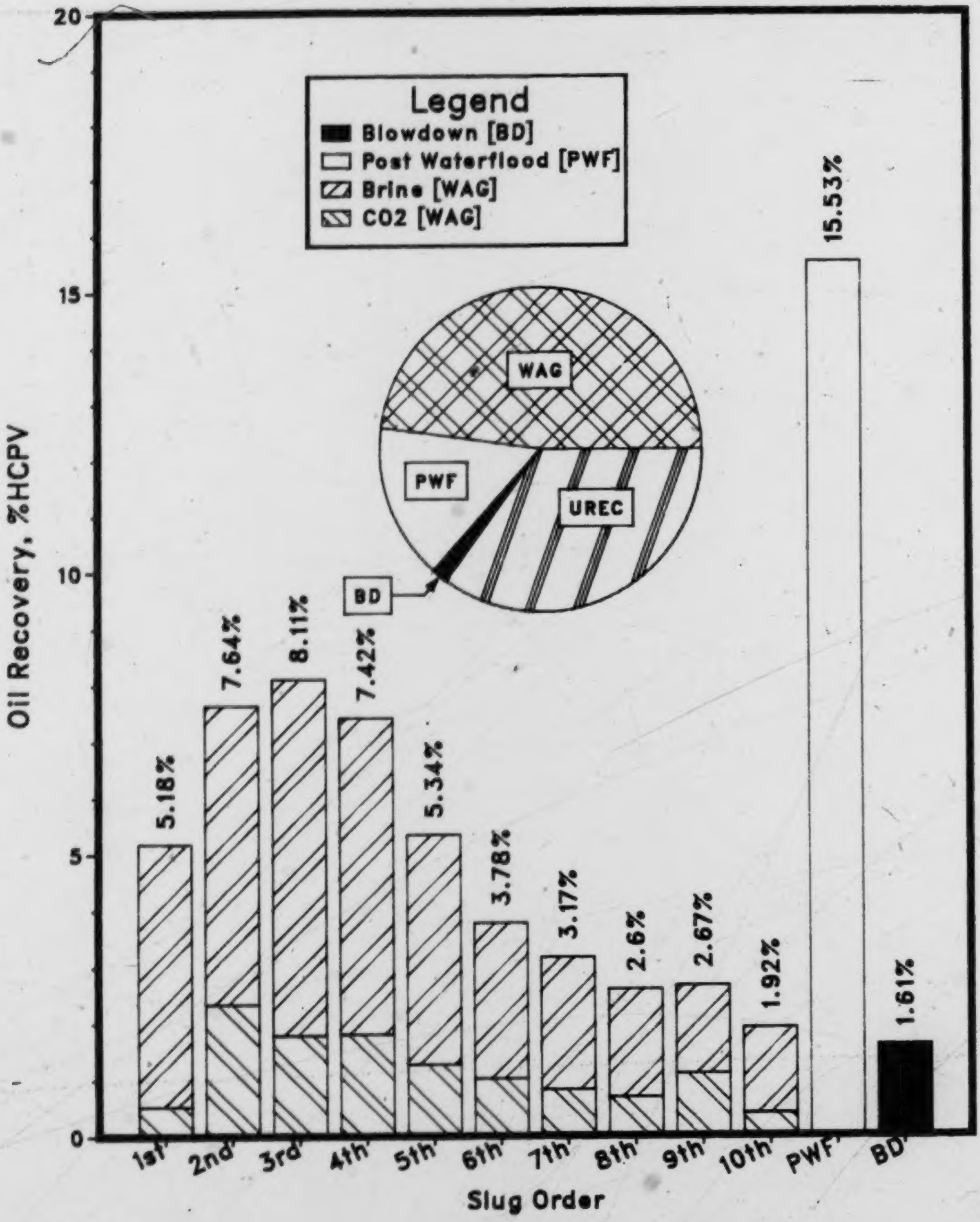
For the purpose of this study, secondary recovery is defined as the implementation of the WAG process on a reservoir that has not undergone any previous forms of depletion. Tertiary recovery is defined as the implementation of the WAG process after the reservoir has been waterflooded to a preset economic limit (WOR ≥ 20:1).

The effect of oil viscosity was studied for the two cases of secondary and tertiary recovery. Secondary recovery of a 1055 mP•s and a 150 mPa•s oil was studied in Runs LC7 and LC22, respectively. Tertiary recovery of the aforementioned oils was studied in Runs LC8(a,b) and LC23(a,b). The 'a' portion of the run refers to the initial waterflood, while the 'b' portion refers to the tertiary flood (see Table 6.1).

The 1.00 MPa 20% HCPV CO_2 4:1 WAG process (10-slugs), at constant velocity, was utilized for all four runs. For the secondary recovery case, the total volume of carbon dioxide injected was 20% of the initial oil in place (HCPV basis). For the tertiary case, the total volume of carbon dioxide injected was 20% of the oil remaining after the initial waterflood (RHCPV basis). The initial waterflood [IWF] was terminated when a producing water-oil ratio of 20:1 had been reached.

Secondary Recovery Mode

The oil recovery distributions for Runs LC7 and LC22 are given in Figures 6.8 and 6.39, respectively. The oil viscosity for Run LC7 was 1055.3 mPa•s (at 23°C), while the viscosity for Run LC22 was 150 mPa•s (at 23°C). As can be seen, the distributions for both oils were very similar except in magnitude. In all but the first slug, the volume of oil recovered (both due to gas and water displacement) for the low viscosity oil was greater. As well, the post-waterflood and blowdown phase recoveries were greater for the low viscosity oil. In both cases, the post-waterflood recovery dominated the relative slug recoveries. The total oil recovery for the 150 mPa•s oil was 65% HCPV while the



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 150.0 mPa.s
ϕ = 36.67 %, k = 11.414 darcies, S_o = 88.20 %, S_{wc} = 11.80 %

[0.20 HCPV CO2 @ 1.00MPa (0.09 g-mol) 4:1 WAG, 10-Slugs, Wainwright]

Figure 6.39 Oil Recovery Distribution of Run LC22.

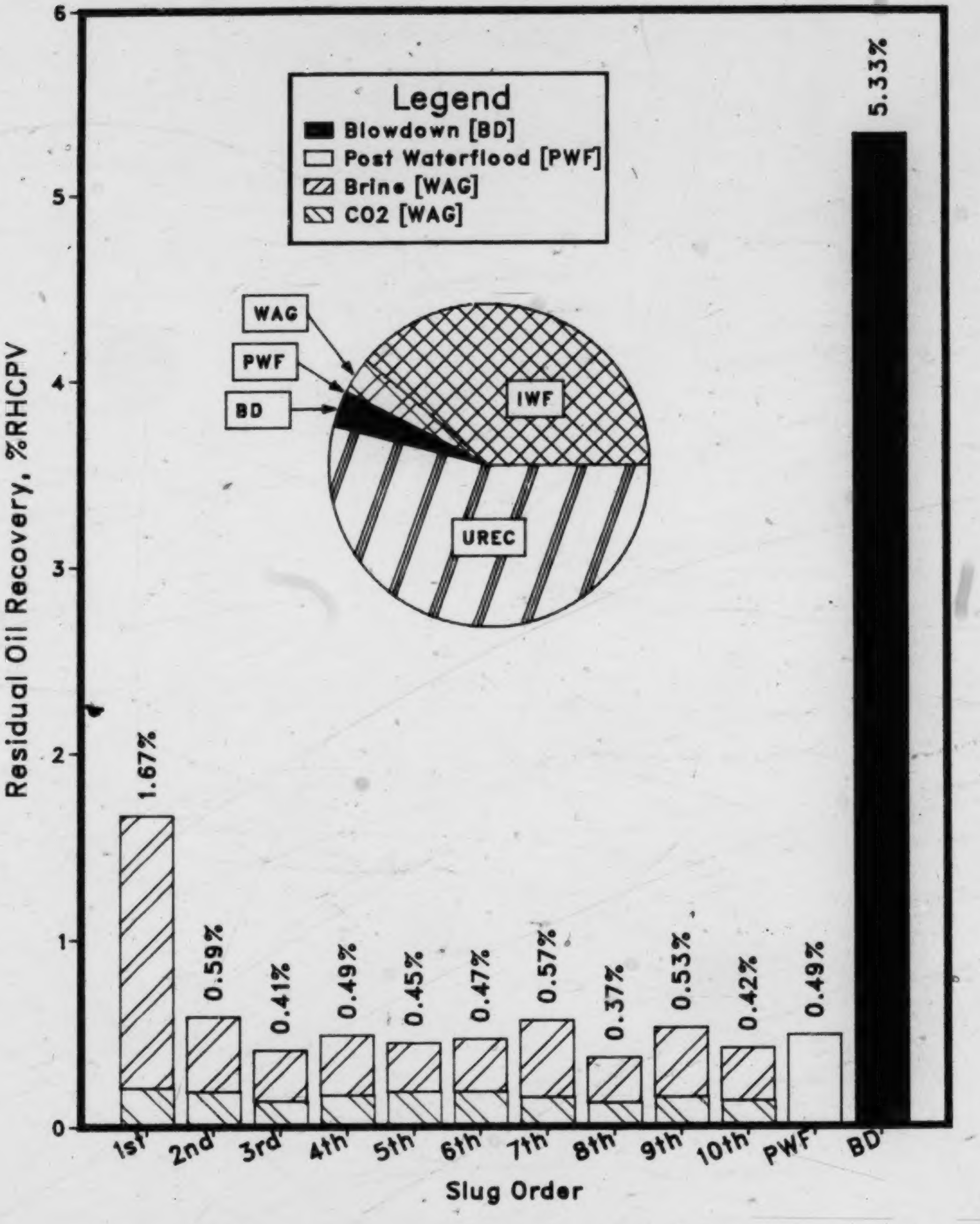
total recovery for the 1055 mP•s oil was 47%, a difference of almost 20 percentiles.

Figures C.7 and C.22 show the production history plots for Runs LC7 and LC22, respectively. It is seen that the lower viscosity oil exhibited much lower producing gas-oil ratios during the WAG process. As well, a smaller increase in the oil-produced:fluid-injected ratio was observed for the more viscous oil. The recovery curves in Figure 6.42 show the vast difference in displacement efficiency for the two oils. The bar chart (inset) reflects this improved efficiency by indicating the much higher initial slope for the 150 mPa•s oil. As well, it is shown that after the start of the post-waterflood, the 150 mPa•s oil displacement continually diverges upward (more efficient) and away from the 1055 mPa•s oil curve. This is to be expected because the viscosity ratio between the displaced (oil) and displacing phase (water+CO_2) has been reduced by a factor of approximately seven when considering the low viscosity relative to the high viscosity oil.

The carbon dioxide requirement for the high viscosity and low viscosity oils were very low, 4.44 and 3.43 sm^3/sm^3, respectively. This indicates an excellent utilization of the injected carbon dioxide for the 4:1 WAG process at low pressure in secondary recovery applications. Carbon dioxide retention was also low for both oils because of the low pressure.

Tertiary Recovery Mode

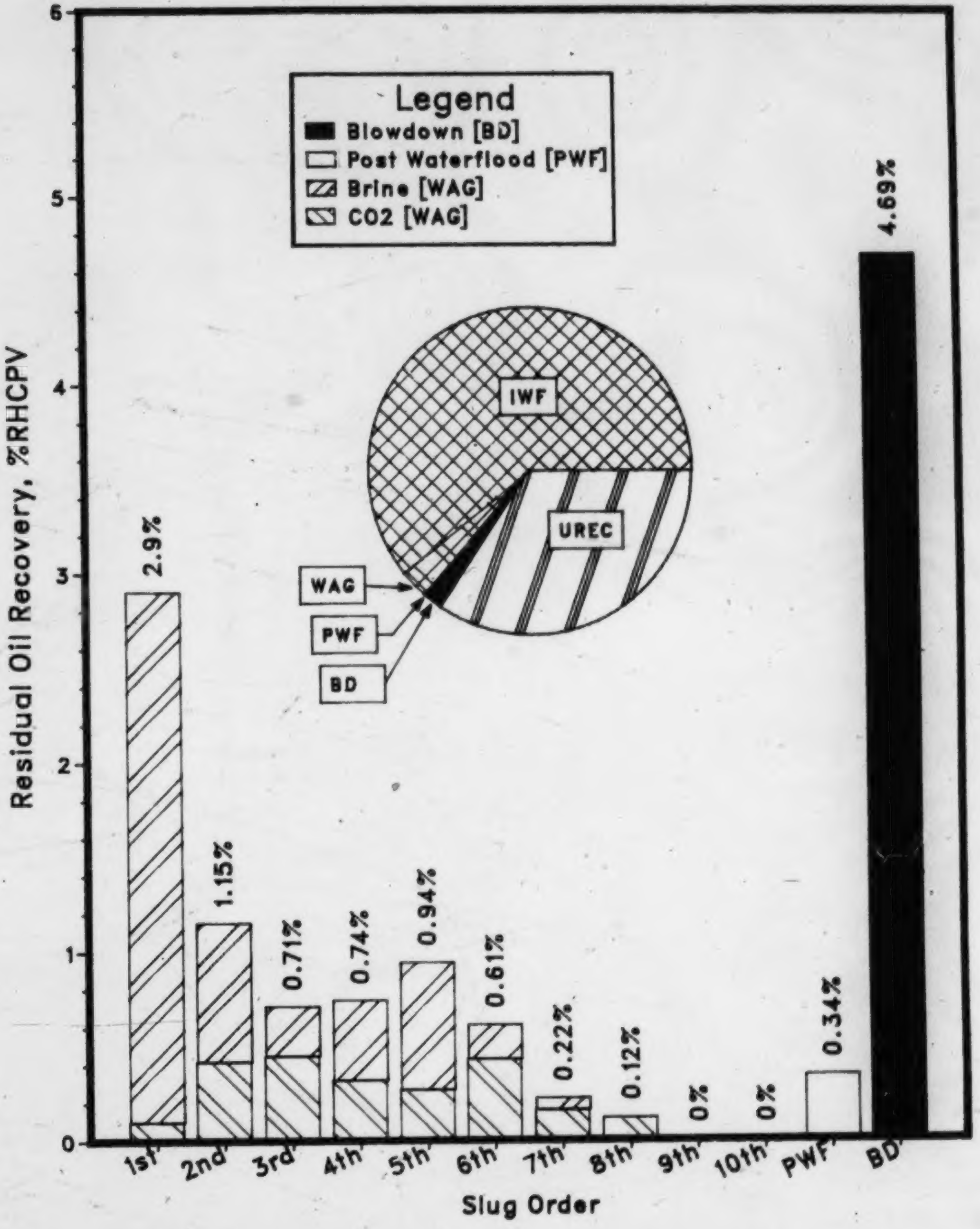
Figures 6.40 and 6.41 show the residual oil recovery distribution for Runs LC8(b) and LC23(b), respectively. The pie chart illustrates that in both cases, the initial waterflood [IWF] dominated the fractional recovery for the entire process, more so for the 150 mPa•s oil. For the high viscosity oil, the first slug recovered the most residual oil with the remaining slugs evenly distributed. For the low viscosity oil, the distribution is similar to that for Run LC3, where a tremendous amount of gas had been injected and subsequently wasted. In both cases, the post-waterflood residual oil recovery was limited but the blowdown recovery was significant.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 37.05 %, k = 11.379 darcies, S_o = 89.69 %, S_{wc} = 10.31 %

[2.11 HCPV WF => 0.20 RHCPV CO2 @ 1.00 MPa (0.05 g-mol) 4:1 WAG]

Figure 6.40 Oil Recovery Distribution of Run LC 8.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 150.0 mPa.s
ϕ = 36.22 %, k = 11.457 darcies, S_o = 87.05 %, S_{wc} = 12.95 %

[2.29HCPV WF=>0.20 RHCPV CO2 @ 1.0 MPa(0.05 g-mol)4:1WAG,Wainwright]

Figure 6.41 Oil Recovery Distribution of Run LC23.

A clear indication that the carbon dioxide mobilized residual oil can be obtained from Figures C.8 and C.23. The oil-produced:fluid-injected curve shows the formation of two oil banks. The first bank occurred after water breakthrough and is characterized by a high oil production rate and increasing water-oil ratio. The second bank occurred during the injection of carbon dioxide in the later stage of the experiment. This bank is characterized by the rapid drop in water-oil ratio and gradual increase in gas-oil ratio after carbon dioxide breakthrough due to the swelling of oil resulting in $S_o > S_{or}$. This indicates that small amounts of carbon dioxide can mobilize residual oil. The magnitude of the second oil bank was greater for the high viscosity oil.

Comparison of the tertiary recovery mode with the secondary recovery mode, for the two very different viscosity oils, reveals several interesting points. Figure 6.42 indicates that secondary and tertiary modes of oil recovery for the 150 mPa•s oil ultimately have approximately the same results. The total oil recovery for Run LC22 (secondary) was 64.96% HCPV, while for Run LC23 (tertiary) it was 60.71% HCPV. The residual oil recovery was 12.4% RHCPV. The point where the tertiary and secondary mode recovery curves intersect [≈ 2 PV] corresponds to the beginning of the tertiary WAG process, another indication that carbon dioxide mobilized residual oil. Figure 6.42 also clearly indicates that the secondary mode of recovery performed better than the tertiary mode for the 1055 mPa•s oil. The total oil recovery for Run LC7 (secondary) was 46.97% HCPV and for LC8 (tertiary) was 46.0% HCPV. The residual oil recovery was 11.8% RHCPV, almost the same as for the low viscosity case.

The overall carbon dioxide requirement dropped considerably for both the high and low viscosity tertiary runs. This is to be expected because much less gas was injected and more water was present for carbon dioxide to dissolve into. Table 6.1 indicates that the carbon dioxide requirement on a residual oil recovery basis increased almost four-fold over the secondary runs. This would incur a significant cost to operators considering the tertiary recovery of

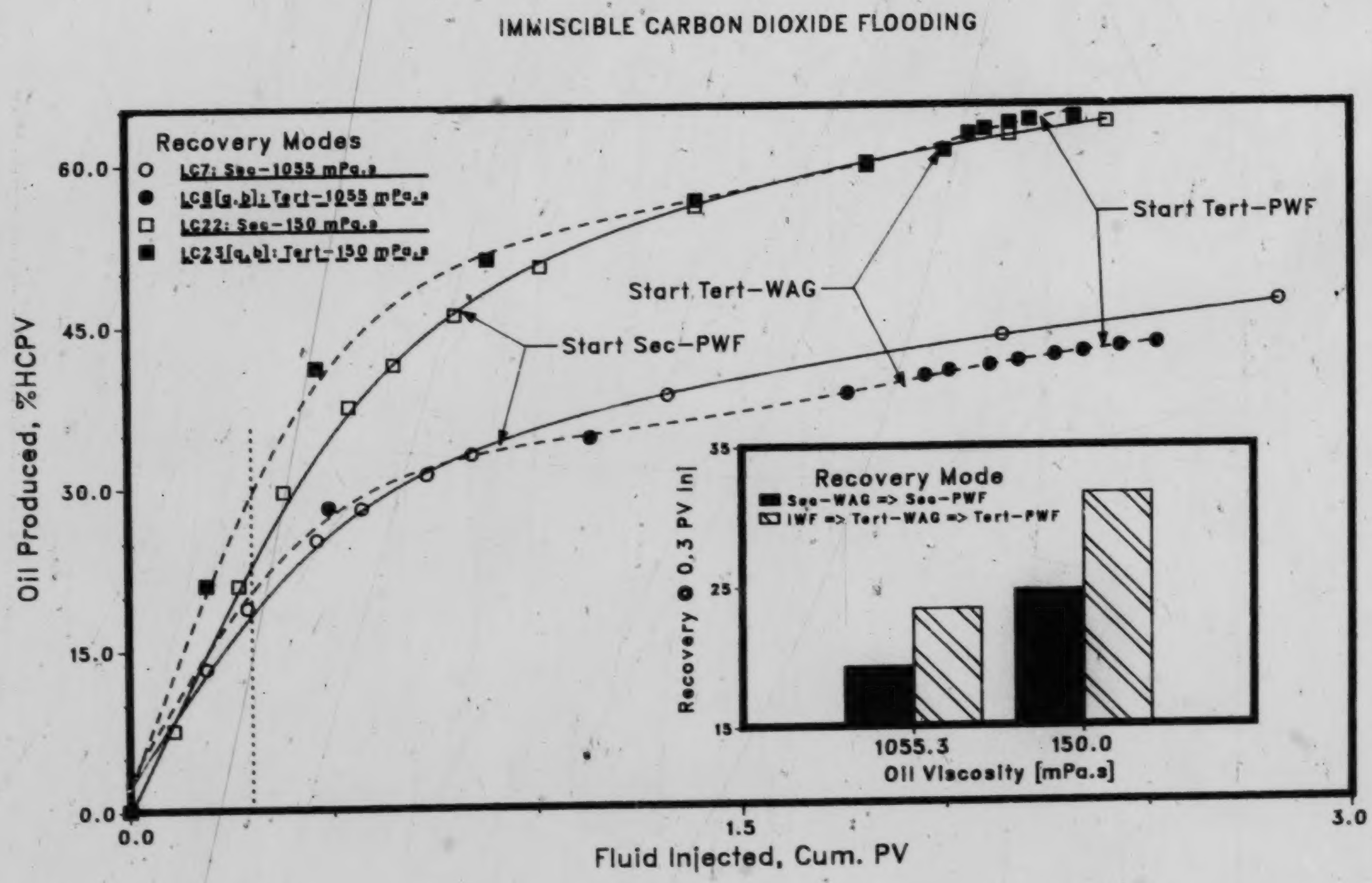


Figure 6.42 – Effect of Oil Viscosity on Secondary and Tertiary Recovery Modes at 1.00 MPa.

heavy oils. Table 6.1 also indicates a tremendous increase in carbon dioxide retention for the high viscosity oil undergoing tertiary recovery. This is due to the higher solubility of carbon dioxide in the 1055 mPa•s oil.

Overall, the results indicate that the immiscible carbon dioxide WAG process at low pressure did not perform well for the displacement of low viscosity oils in either the secondary or tertiary recovery modes. This is because the reduction in viscosity is an exponential function of initial oil viscosity. Therefore, greater benefits from reduced mobility ratio are expected for the case of higher initial oil viscosity. For tertiary recovery the effect of swelling is predominant as a function of solubility.

Two-Dimensional Model Displacement Results

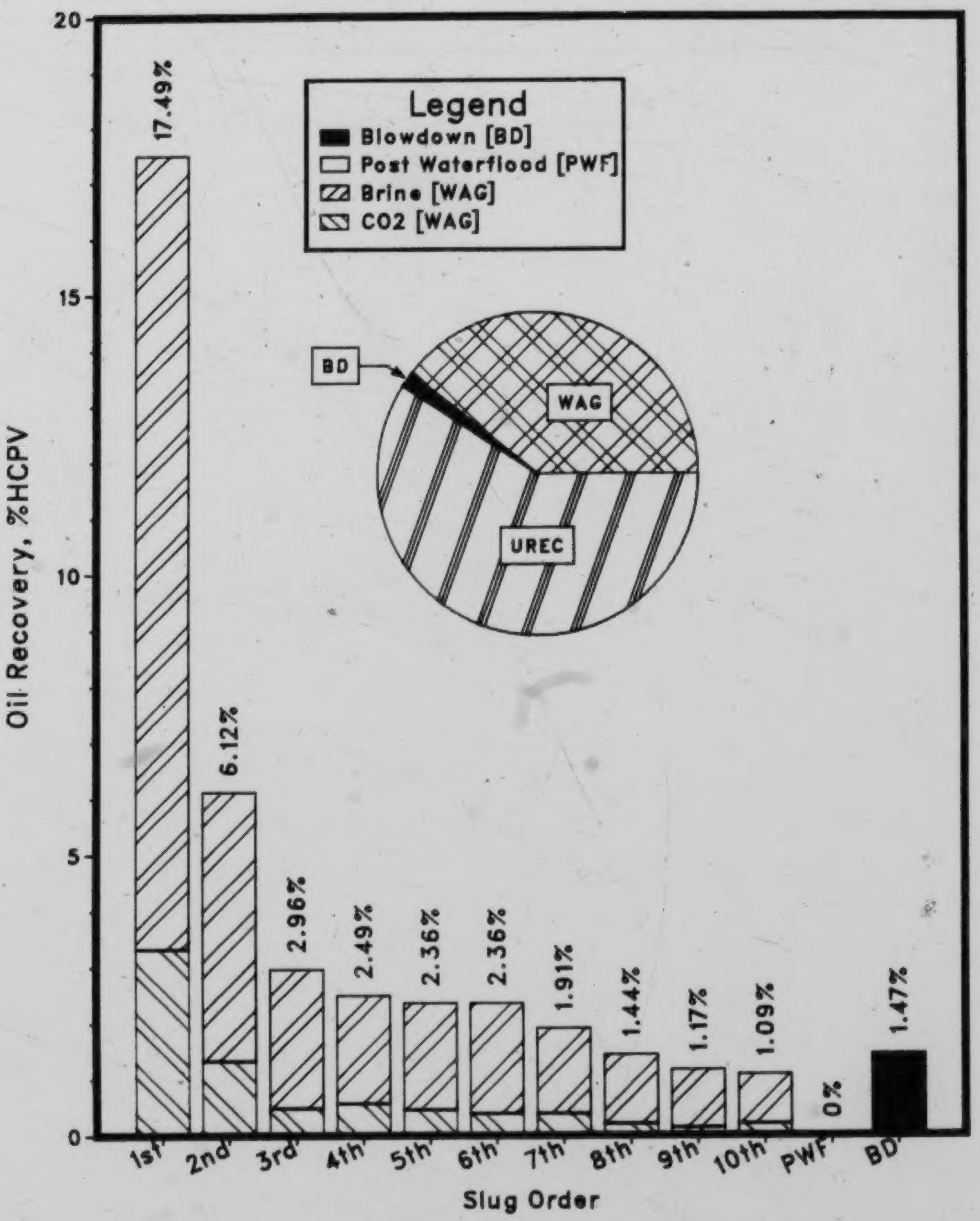
During the course of this study three runs were conducted on the two-dimensional model. Table 6.1 indicates these runs with the suffix "TD". Runs TD1 and TD2 were conducted utilizing oil, water, and sand from the Lloydminster Senlac field in southern Saskatchewan. These runs were conducted to assess the potential of the immiscible carbon dioxide WAG process for this field at various operating pressures.

Run TD3 was conducted using oil and water from the Lloydminster Aberfeldy field, a similar heavy oil reservoir in Saskatchewan. Table 5.1 gives the pertinent reservoir property data for both prototype fields.

For all three two-dimensional runs, the 4:1 WAG process (10-slugs) at constant velocity was utilized. Comparisons cannot be conducted between the two prototypes because different operating pressures and equivalent volumes were used. A detailed description of the two-dimensional experimental apparatus and procedures is presented in Appendix E. Further details about the design and construction of this model have been presented by Rojas[22] and Zhu[15].

Senlac Prototype

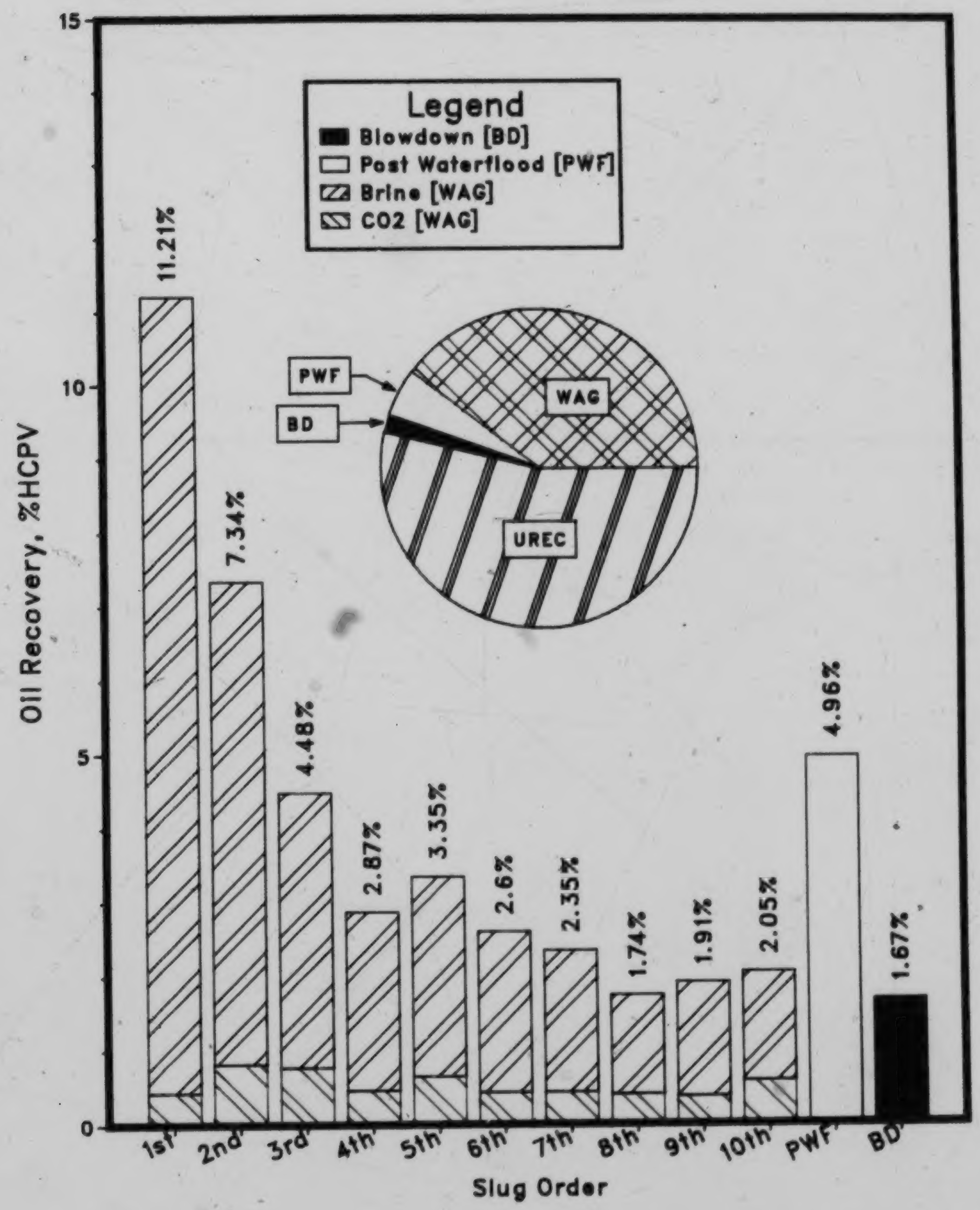
Runs TD1 and TD2 consisted of injecting an equal number of moles of carbon dioxide at two different pressures. The number of moles injected was calculated to be equal to the number of moles required for a 20% CO_2 slug at 5.5 MPa. Subsequently the volume of carbon dioxide injected at 2.5 MPa (TD1) was equivalent to 61% HCPV. The volume of carbon dioxide injected at 4.1 MPa (TD2) was equivalent to 33% HCPV. Pressures of 2.5 and 4.1 MPa were chosen because most of the Senlac reservoirs fell within this range. The viscosity of the Senlac reservoir oil is 3295 mPa•s (at 23°C), considerably higher than the viscosity used for the Aberfeldy experiments (1055 mPa•s at 23°C).



NOTE: Average Run Conditions: Quarter of a 5–Spot, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.776 m/d, μ_o = 3295.0 mPa.s
ϕ = 43.12 %, k = 7.617 darcies, S_o = 86.76 %, S_{wc} = 13.24 %

[0.61 HCPV CO2 @ 2.50 MPa (1.41 g–mol) 4:1 WAG, 10–Slugs, SENLAC]

Figure 6.43 Oil Recovery Distribution of Run TD 1.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 4.10 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.776 m/d, μ_o = 3295.0 mPa.s
ϕ = 41.52 %, k = 7.405 darcies, S_o = 90.10 %, S_{wc} = 9.90 %

[0.33 HCPV CO2 @ 4.10 MPa (1.41 g–mol) 4:1 WAG, 10–Slugs, SENLAC]

Figure 6.44 Oil Recovery Distribution of Run TD 2.

Figures 6.43 and 6.44 show the oil recovery distributions for Runs TD1 and TD2, respectively. For Run TD1 (2.5 MPa) the first slug oil recovery was significant, but oil recovery for the remaining slugs dropped off dramatically. Total oil recovery was 40.86% HCPV. Post-waterflood recovery is absent because a 20:1 water-oil ratio had been reached during the WAG process. The oil recovery distribution for Run TD2 (4.1 MPa) was much more uniform with the first slug being dominant. Total oil recovery was 46.26% HCPV, an increase of 5.4 percentiles. The increase in oil recovery is accounted for by the post-waterflood recovery (4.96%) at the higher pressures as well as the slight increase in blowdown recovery (+ 0.14%). Both post-waterflood recovery and blowdown recovery increased at the higher pressures due to the increased carbon dioxide-oil solubility at increased pressures.

The carbon dioxide requirement dropped from 45.38 to 40.15 sm^3/sm^3 when the pressure was increased from 2.5 to 4.1 MPa. This is due to the larger relative volume of carbon dioxide injected at the lower pressure. The change in carbon dioxide retention was more drastic; dropping from 48.91% to 28.68% of injected gas when the pressure was increased from 2.5 to 4.1 MPa (see Table 6.1). This is due to a larger free gas phase with an increase in volume of carbon dioxide injected.

Figure 6.45 shows the oil recovery curves for the two runs on the basis of cumulative moles of fluid injected. Thus, the effect of pressure, for different equivalent slug volumes may be accounted for because the number of moles of fluid injected in both runs was approximately the same. Therefore, it can be concluded that the dominant parameter is the volume (at reservoir conditions) which effects the overall process. Figure 6.45 shows that the two runs had almost identical initial slopes (bar chart inset) but that Run TD2 (4.1 MPa) performed much better than Run TD1 (2.5 MPa) during most of the flood life.

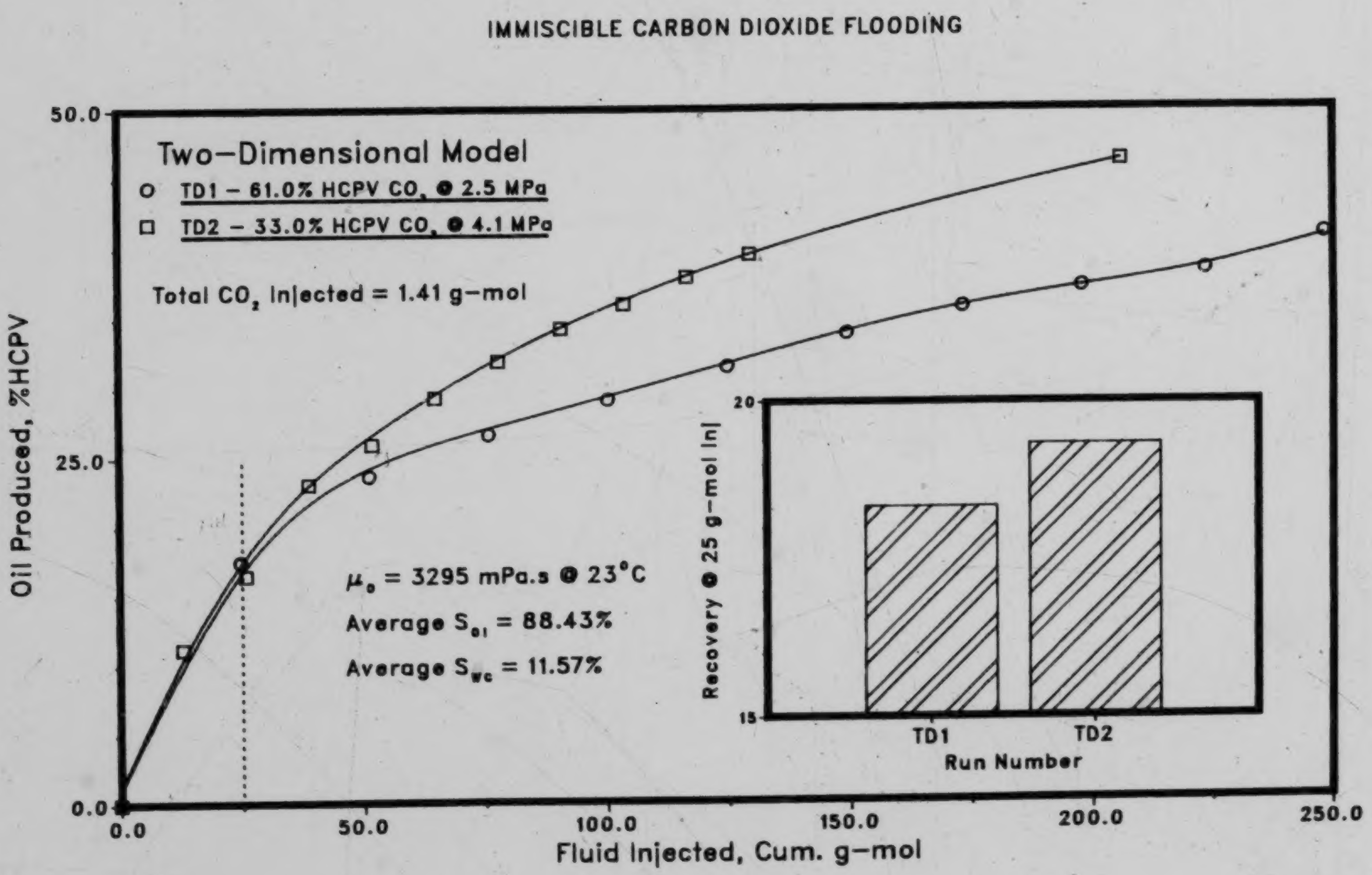


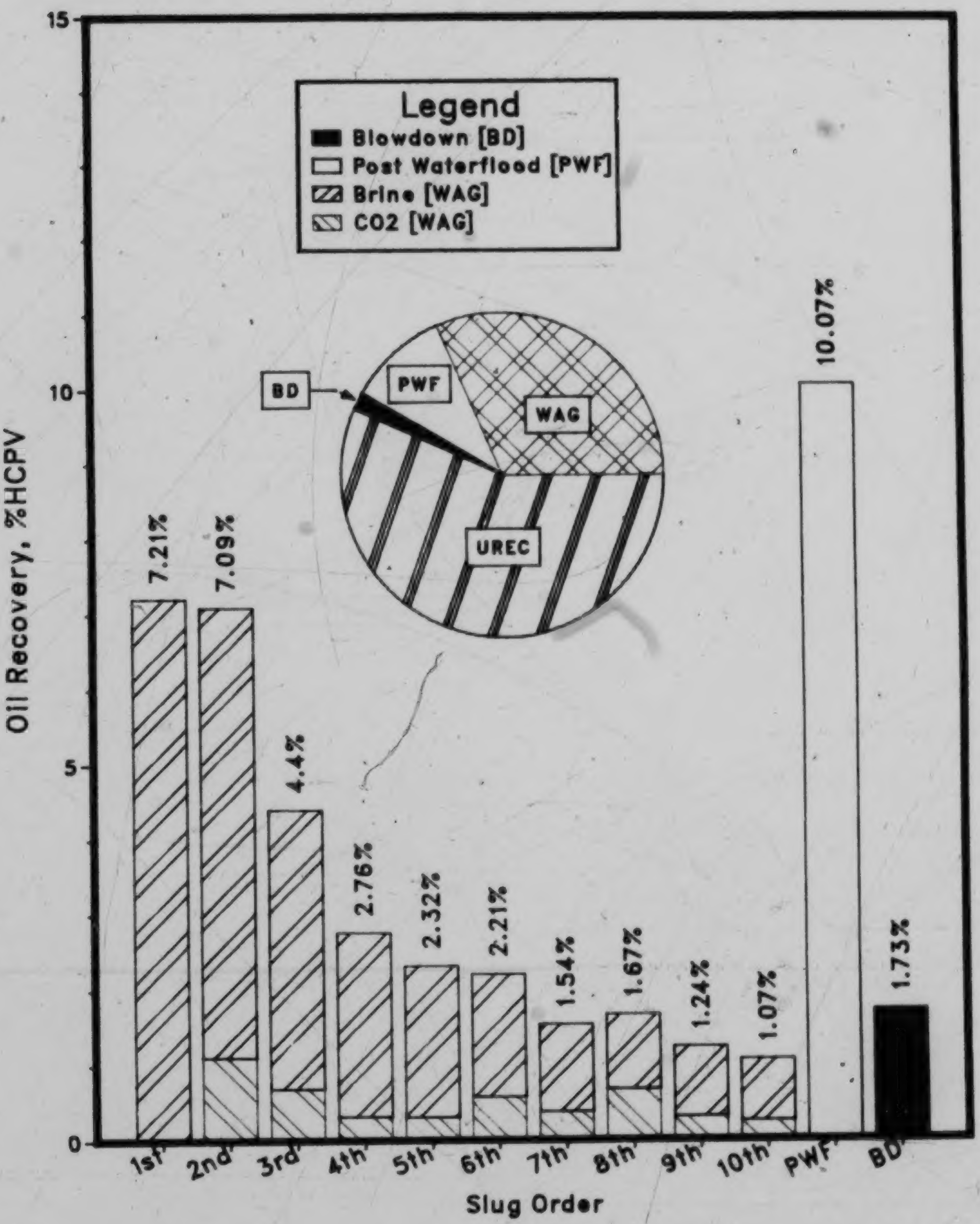
Figure 6.45 – Oil Recovery Curves for Senlac Two–Dimensional Model Runs at 2.5 and 4.1 MPa.

It can concluded that the immiscible carbon dioxide 4:1 WAG process, at high pressures with large carbon dioxide slugs, may be a viable method of recovering heavy oil from the Senlac reservoir.

Aberfeldy Prototype

A single 4:1 WAG type run was conducted for the Aberfeldy prototype on the two-dimensional model. The primary purpose of Run TD3 was for the model comparison at low pressure. Previous investigators[15,22] have done extensive work with this prototype on the two-dimensional model. However, none of the above investigations were conducted at 1.00 MPa.

Figure 6.46 shows the oil recovery distribution for Run TD3. The total oil recovery was 43.3 % HCPV utilizing a 20% carbon dioxide slug. A surprising feature of this run was the almost equal oil recovery for the first two slugs [CO_2+H_2O] injected. As was seen earlier, the first slug usually dominates the WAG recovery. The carbon dioxide requirement was 4.83 sm3/sm3 and the carbon dioxide retention was 65.99% injected.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.831 m/d, μ_o = 1055.3 mPa.s
ϕ = 40.59 %, k = 13.312 darcies, S_o = 91.33 %, S_{wc} = 8.67 %

[0.20 HCPV CO2 @ 1.00 MPa (0.16 g–mol) 4:1 WAG, 10–Slugs]

Figure 6.46 Oil Recovery Distribution of Run TD 3.

Chapter VII

Conclusions

This investigation was designed to examine the performance of the immiscible carbon dioxide water-alternating-gas (WAG) process at low pressures. In addition, a review and comparison of the experimental studies preceding this work have been included. The conclusions are based upon a series of twenty-six experiments conducted on two physical models, scaled and partially scaled, of the Lloydminster Aberfeldy field, employing three different crude oils.

1. The low pressure carbon dioxide WAG process is dependent on the total carbon dioxide slug size and the number of WAG slugs. The optimum total carbon dioxide slug size appears to be in the range of 35 to 40% HCPV, at reservoir conditions, for the linear core model. Increased oil recovery with the larger slugs was limited to less than 15 percentiles, but the time required to recover this additional oil was prohibitive. The optimum number of WAG slugs is ten, the first slug being the most important in terms of oil recovery.

2. The WAG ratio and velocity had considerable effect on the performance of heavy oil (15°API, 1055 mPa•s) recovery at low pressure. The 4:1 WAG ratio at a high velocity recovered the most oil (46.97% HCPV). Some basic economic parameters of this process were: an incremental recovery of nine percentiles over a waterflood, carbon dioxide requirement of 4.44 sm^3/sm^3, and a carbon dioxide retention of 8.37% injected gas.

3. The effect of operating pressure, for equivalent slug volumes, is related to the initial oil viscosity. Recovery increased with pressure (e.g. 47% at 1.0 MPa [LC7] and 49% at 5.5 MPa [LC20] for a 20% HCPV CO_2 slug), more in the lower pressure range, for a 1055 mPa•s oil. A similar effect of pressure was observed for the Senlac oil (3295 mPa•s). Increased recovery with pressure is due to higher carbon dioxide-oil solubility and increased

mobility control as the viscosity of carbon dioxide-oil mixtures decreases with pressure.

4. The WAG process operating in the secondary recovery mode performed well in recovering incremental heavy oil [1055 mPa•s], over and above that for a waterflood (≈ 9 percentiles). In the case of a lighter oil [150 mPa•s], incremental recoveries were not significant (≈ 4 percentiles). Increased secondary recovery is due primarily to reduced oil viscosity. Reduction in viscosity is an exponential function of pressure and therefore more significant for initially higher oil viscosities.

5. For both the light and heavy oils, there was a clear indication that carbon dioxide WAG flooding mobilized residual oil. The residual oil recovery for the 150 mPa•s oil was 12.4% RHCPV, and for the 1055 mP•s oil it was 11.8% RHCPV. However, the incremental recovery by the carbon dioxide WAG process over secondary recovery was insignificant for the 150 mPa•s oil. Increased tertiary recovery is due primarily to oil swelling and therefore the average oil saturation is increased over the residual oil saturation.

6. The scaling factor representing gravitational-to-viscous forces was used successfully in comparing the linear core model runs with the two-dimensional model runs at both low and high pressures. Differences may be accounted for by model geometry. For reliable prediction of a field test, the two-dimensional model is recommended; the linear model is invaluable for screening studies at about one-third the cost.

Chapter VIII

Recommendations For Further Studies

The following studies are recommended to further complement the work undertaken in this study:

1. The effect of a small amount of surfactant to the water to generate a foam with carbon dioxide in the porous medium should increase the mobility control of water and carbon dioxide and better results should be achieved.

2. The oil recovery distribution showed the importance of the first slug (CO_2+H_2O) oil recovery. The injection of proportionally more carbon dioxide during the earlier portion of the WAG process may capitalize on this phenomenon.

3. Carbon dioxide breakthrough occurs relatively early in the WAG process. During the carbon dioxide injection stage, the production well should be closed. This will delay carbon dioxide breakthrough and increase carbon dioxide-oil solubility due to the increase in pressure. As well, a soak period should be investigated for this variation of carbon dioxide injection.

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Appendix A

Production Histories of all Runs in Tabulated Form

TABLE A 1

RESULTS OF RUN LC 1
[1.92 HCPV Waterflood @ 1.00 MPa]

Porosity [%] = 35.0
Oil Viscosity [mPa.s] = 1059.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 0.0

Pore Volume [cm3] = 1065.0
Initial Oil Saturation [%] = 93.0
Hydrocarbon Pore Volume [cm3] = 989.5
Carbon Dioxide Retention [%inj] = 0.0

Connate Water Saturation [%] = 7.0
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 11.1000
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.20	0.97	0.0	176.0	0.165	0.0	9.05	146.95	146.95	14.85	0.06	0.0	0.835
1.16	1.00	0.0	83.0	0.078	0.0	45.50	38.50	185.45	18.74	1.18	0.0	0.464
1.16	0.99	0.0	91.0	0.085	0.0	62.00	32.00	217.45	21.98	1.94	0.0	0.352
1.15	0.99	0.0	86.8	0.081	0.0	66.75	22.25	239.70	24.22	3.00	0.0	0.256
1.12	1.00	0.0	110.3	0.104	0.0	89.40	20.60	260.30	26.31	4.34	0.0	0.187
1.11	0.99	0.0	118.5	0.111	0.0	103.00	17.00	277.30	28.02	6.06	0.0	0.143
1.05	0.90	0.0	176.1	0.165	0.0	160.25	19.75	297.05	30.02	8.11	0.0	0.112
0.84	0.80	0.0	171.8	0.161	0.0	159.50	14.50	311.55	31.48	11.00	0.0	0.084
1.37	1.14	0.0	177.3	0.166	0.0	164.50	15.50	327.05	33.05	10.61	0.0	0.087
1.04	1.00	0.0	159.0	0.149	0.0	151.50	10.50	337.55	34.11	14.43	0.0	0.066
1.10	1.04	0.0	52.0	0.049	0.0	47.50	5.00	342.55	34.62	9.50	0.0	0.096
1.10	1.02	0.0	147.1	0.138	0.0	140.80	9.20	351.75	35.55	15.30	0.0	0.063
1.15	1.02	0.0	185.7	0.174	0.0	174.80	12.50	364.25	36.81	13.98	0.0	0.067
1.16	1.13	0.0	170.1	0.160	0.0	158.00	13.00	377.25	38.12	12.15	0.0	0.076
0.10	0.10	0.0	0.0	0.0	0.0	18.00	10.00	387.25	39.14	1.80	0.0	

TABLE A 2

RESULTS OF RUN LC 2
[1.44 HCPV Waterflood @ 1.00 MPa]

Porosity [%] = 35.0
Oil Viscosity [mPa.s] = 1059.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 0.0

Pore Volume [cm3] = 1103.0
Initial Oil Saturation [%] = 90.0
Hydrocarbon Pore Volume [cm3] = 992.4
Carbon Dioxide Retention [%inj] = 0.0

Connate Water Saturation [%] = 10.0
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 5.5801
Average Flow Velocity [m/d] = 0.256

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.08	0.95	0.0	171.6	0.156	0.0	0.05	141.95	141.95	14.30	0.00	0.0	0.827
1.06	1.00	0.0	67.0	0.061	0.0	3.52	74.99	216.94	21.86	0.05	0.0	1.119
1.06	0.99	0.0	25.0	0.023	0.0	16.50	21.00	237.94	23.98	0.79	0.0	0.840
1.06	1.00	0.0	90.3	0.082	0.0	64.50	28.50	266.44	26.85	2.26	0.0	0.316
0.94	0.92	0.0	119.1	0.108	0.0	101.00	20.50	286.94	28.91	4.93	0.0	0.172
0.86	0.85	0.0	124.0	0.112	0.0	110.00	17.50	304.44	30.68	6.29	0.0	0.141
1.07	1.02	0.0	53.4	0.048	0.0	57.50	6.50	310.94	31.33	8.85	0.0	0.122
1.02	0.98	0.0	153.1	0.139	0.0	128.50	15.50	326.44	32.89	8.29	0.0	0.101
1.06	1.02	0.0	130.6	0.118	0.0	124.50	9.50	335.94	33.85	13.11	0.0	0.073
1.03	0.90	0.0	109.5	0.099	0.0	103.50	8.50	344.44	34.71	12.18	0.0	0.078
1.04	1.02	0.0	138.3	0.125	0.0	125.50	13.50	357.94	36.07	9.30	0.0	0.098
0.99	0.98	0.0	129.4	0.117	0.0	117.20	11.80	369.74	37.26	9.83	0.0	0.091
0.96	0.95	0.0	117.3	0.106	0.0	116.80	3.20	372.94	37.58	36.50	0.0	0.027

TABLE A3

RESULTS OF RUN LC3

[1.79 HCPV CO2 @ 1.00 MPa (0.77 g-mol) 4:1 WAG, 10-Slugs]

Porosity [%] = 36.6
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 30.49

Pore Volume [cm3] = 1137.5
Initial Oil Saturation [%] = 87.3
Hydrocarbon Pore Volume [cm3] = 993.3
Carbon Dioxide Retention [%inj] = 13.83

Connate Water Saturation [%] = 12.7
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 10.6571
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.19	1.01	146.9	70.9	0.191	0.0	0.0	67.00	67.00	6.75	0.0	0.0	0.308
1.40	1.00	0.0	76.3	0.067	0.0	0.0	57.00	124.00	12.48	0.0	0.0	0.747
1.21	1.00	0.0	58.4	0.051	0.0	16.70	43.30	167.30	16.84	0.39	0.0	0.741
1.11	1.00	0.0	60.0	0.053	0.0	29.31	32.69	199.99	20.13	0.90	0.0	0.545
1.15	0.97	0.0	58.5	0.051	0.0	37.12	23.08	223.07	22.46	1.61	0.0	0.395
1.20	0.98	0.0	58.3	0.051	0.0	44.00	16.00	239.07	24.07	2.75	0.0	0.275
1.11	1.00	0.0	43.4	0.038	0.0	31.80	13.20	252.27	25.40	2.41	0.0	0.304
1.07	0.98	0.0	145.4	0.128	0.0	115.80	30.30	282.57	28.45	3.82	0.0	0.208
1.06	0.99	0.0	136.5	0.120	0.0	115.60	23.10	305.67	30.77	5.00	0.0	0.169
1.00	0.95	182.5	0.0	0.160	0.0	52.10	8.90	314.57	31.67	5.85	0.0	0.049
1.00	1.00	0.0	219.1	0.193	0.0	149.00	16.80	331.37	33.36	8.87	0.0	0.077
1.00	1.00	0.0	189.2	0.166	0.0	175.50	16.40	347.77	35.01	10.70	0.0	0.087
1.00	1.00	0.0	201.3	0.177	0.134	187.70	15.10	362.87	36.53	12.43	8.87	0.075
1.00	1.00	0.0	97.9	0.086	0.155	90.10	9.80	372.67	37.52	9.19	15.82	0.100
1.00	0.96	176.9	0.0	0.156	0.100	64.50	6.40	379.07	38.16	10.08	15.63	0.036
1.01	1.00	0.0	226.9	0.199	0.417	156.30	10.40	389.47	39.21	15.03	40.10	0.046
1.00	1.00	0.0	195.6	0.172	0.382	181.50	14.40	403.87	40.66	12.60	26.53	0.074

TABLE A3 (CONTINUED)

RESULTS OF RUN LC3
[1.79 HCPV CO2 @ 1.00 MPa (0.77 g-mol) 4:1 WAG, 10-Slugs]

Porosity [%] = 36.6
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 30.49

Pore Volume [cm3] = 1137.5
Initial Oil Saturation [%] = 87.3
Hydrocarbon Pore Volume [cm3] = 993.3
Carbon Dioxide Retention [%inj] = 13.83

Connate Water Saturation [%] = 12.7
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 10.6571
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.00	1.00	0.0	288.7	0.254	0.523	272.60	11.70	415.57	41.84	23.30	44.70	0.041
0.98	0.95	180.7	0.0	0.159	0.138	59.70	5.30	420.87	42.37	11.26	26.04	0.029
1.00	0.97	0.0	219.4	0.193	0.431	163.30	6.50	427.37	43.03	25.12	66.31	0.030
1.00	1.00	0.0	182.9	0.161	0.480	168.80	7.60	434.97	43.79	22.21	63.16	0.042
1.00	1.00	0.0	305.3	0.268	0.650	289.50	15.30	450.27	45.33	18.92	42.48	0.050
0.97	0.95	182.7	0.0	0.161	0.125	67.30	3.70	453.97	45.70	18.19	33.78	0.020
1.00	1.00	0.0	249.1	0.219	0.434	181.50	8.50	462.47	46.56	21.35	51.06	0.034
1.00	1.00	0.0	163.3	0.144	0.502	156.40	3.50	465.97	46.91	44.69	143.43	0.021
1.00	1.00	0.0	310.7	0.273	0.629	297.50	16.50	482.47	48.57	18.03	38.12	0.053
0.96	0.94	185.0	0.0	0.163	0.181	72.00	3.70	486.17	48.95	19.46	48.92	0.020
1.00	1.00	0.0	240.9	0.212	0.397	174.30	5.30	491.47	49.48	32.89	74.91	0.022
1.00	1.00	0.0	192.5	0.169	0.460	184.00	4.40	495.87	49.92	41.82	104.55	0.023
1.00	1.00	0.0	274.2	0.241	0.787	266.00	8.00	503.87	50.73	33.25	98.38	0.029
0.99	0.97	178.8	0.0	0.157	0.138	59.30	4.80	508.67	51.21	12.35	28.75	0.027
1.00	1.00	0.0	238.4	0.210	0.430	183.70	5.20	513.87	51.73	35.33	82.69	0.022
1.00	1.00	0.0	180.9	0.159	0.490	175.80	4.20	518.07	52.16	41.86	116.67	0.023
1.00	1.00	0.0	288.2	0.253	0.663	273.20	11.10	529.17	53.28	24.61	59.73	0.039

TABLE A3 (CONTINUED)

RESULTS OF RUN LC3
[1.79 HCPV CO2 @ 1.00 MPa (0.77 g-mol) 4:1 WAG, 10-Slugs]

Porosity [%] = 36.6
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 30.49

Pore Volume [cm3] = 1137.5
Initial Oil Saturation [%] = 87.3
Hydrocarbon Pore Volume [cm3] = 993.3
Carbon Dioxide Retention [%inj] = 13.83

Connate Water Saturation [%] = 12.7
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 10.6571
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
0.97	0.96	182.7	0.0	0.161	0.161	43.10	3.80	532.97	53.66	11.34	42.37	0.021
1.00	1.00	0.0	261.4	0.230	0.471	188.10	5.20	538.17	54.18	36.17	90.58	0.020
1.00	1.00	0.0	173.1	0.152	0.615	167.60	3.50	541.67	54.53	47.89	175.71	0.020
1.00	1.00	0.0	273.2	0.240	0.709	258.90	9.10	550.77	55.45	28.45	77.91	0.033
0.99	0.97	178.8	0.0	0.157	0.211	81.20	6.70	557.47	56.12	12.12	31.49	0.037
1.00	1.00	0.0	268.1	0.236	0.690	200.00	5.70	563.17	56.70	35.09	121.05	0.021
1.00	1.00	0.0	201.3	0.177	0.727	183.00	6.80	569.97	57.38	26.91	106.91	0.034
1.00	1.00	0.0	238.3	0.209	0.683	275.60	9.40	579.37	58.33	29.32	72.66	0.039
0.95	0.94	186.8	0.0	0.164	0.212	65.00	3.90	583.27	58.72	16.67	54.36	0.021
1.00	1.00	0.0	221.3	0.195	0.595	179.50	4.60	587.87	59.18	39.02	129.35	0.021
1.00	1.00	0.0	251.0	0.221	0.559	225.80	3.60	591.47	59.55	62.72	155.28	0.014
1.00	1.00	0.0	2[illegible]8.3	0.196	0.473	218.70	4.60	596.07	60.01	47.54	102.83	0.021
0.10	0.10	0.0	0.0	0.0	1.161	148.30	9.60	605.67	60.98	15.45	120.94	

TABLE A4

RESULTS OF RUN LC4
[0.89 HCPV CO2 @ 1.00 MPa (0.39 g-mol) 4:1 WAG, 10-Slugs]

Porosity [%] = 36.3
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 17.37

Pore Volume [cm3] = 1130.0
Initial Oil Saturation [%] = 89.3
Hydrocarbon Pore Volume [cm3] = 1008.5
Carbon Dioxide Retention [%inj] = 10.25

Connate Water Saturation [%] = 10.7
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 11.5380
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.00	0.97	89.8	0.0	0.079	0.384	0.0	19.20	19.20	1.90	0.0	20.00	0.214
1.20	1.00	0.0	88.3	0.078	0.401	0.0	56.30	75.50	7.49	0.0	7.12	0.637
1.17	1.00	0.0	59.9	0.053	0.067	0.0	58.80	134.30	13.32	0.0	1.14	0.982
1.12	1.00	0.0	87.6	0.078	0.089	26.90	61.10	195.40	19.37	0.44	1.46	0.697
1.00	1.00	0.0	123.3	0.109	0.121	70.60	53.50	248.90	24.68	1.32	2.26	0.434
1.02	0.96	88.0	0.0	0.078	0.031	31.60	16.30	265.20	26.30	1.94	1.90	0.185
1.00	1.00	0.0	162.0	0.143	0.197	95.80	26.50	291.70	28.92	3.62	7.43	0.164
1.00	1.00	0.0	197.2	0.175	0.131	169.00	26.90	318.60	31.59	6.28	4.87	0.136
1.00	0.94	90.3	0.0	0.080	0.031	46.20	9.80	328.40	32.56	4.71	3.16	0.108
1.00	1.00	0.0	184.6	0.163	0.167	123.60	14.50	342.90	34.00	8.52	11.52	0.079
1.00	1.00	0.0	174.6	0.155	0.075	148.70	26.30	369.20	36.61	5.65	2.85	0.151
1.00	0.98	90.7	0.0	0.080	0.011	39.40	7.90	377.10	37.39	4.99	1.39	0.087
1.00	1.00	0.0	180.1	0.159	0.255	128.30	12.10	389.20	38.59	10.60	21.07	0.067
1.00	1.00	0.0	179.1	0.158	0.302	164.80	13.20	402.40	39.90	12.48	22.88	0.074
1.00	0.98	88.9	0.0	0.079	0.018	54.10	6.40	408.80	40.53	8.45	2.81	0.072
1.00	1.00	0.0	175.6	0.155	0.589	112.90	9.20	418.00	41.45	12.27	64.02	0.052
1.00	1.00	0.0	183.6	0.163	0.388	173.10	8.80	426.80	42.32	19.67	44.09	0.048

TABLE A4 (CONTINUED)

RESULTS OF RUN LC4
[0.89 HCPV CO2 @ 1.00 MPa (0.39 g-mol) 4:1 WAG, 10-Slugs]

Porosity [%] = 36.3
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 17.37

Pore Volume [cm3] = 1130.0
Initial Oil Saturation [%] = 89.3
Hydrocarbon Pore Volume [cm3] = 1008.5
Carbon Dioxide Retention [%inj] = 10.25

Connate Water Saturation [%] = 10.7
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 11.5380
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
0.98	0.96	91.3	0.0	0.081	0.094	49.70	5.30	432.10	42.84	9.38	17.74	0.058
1.00	1.00	0.0	183.1	0.162	0.326	127.50	8.60	440.70	43.70	14.83	37.91	0.047
1.00	1.00	0.0	174.1	0.154	0.214	164.90	8.00	448.70	44.49	20.61	26.75	0.046
1.01	0.96	92.9	0.0	0.082	0.014	41.80	11.10	459.80	45.59	3.77	1.26	0.119
1.00	1.00	0.0	189.6	0.168	0.264	139.70	8.20	468.00	46.40	17.04	32.20	0.043
1.00	1.00	0.0	174.1	0.154	0.384	165.70	6.30	474.30	47.03	26.30	60.95	0.036
1.05	1.00	83.2	0.0	0.074	0.131	52.20	3.90	478.20	47.42	13.38	33.59	0.047
1.00	1.00	0.0	196.4	0.174	0.596	142.00	6.60	484.80	48.07	21.52	90.30	0.034
1.00	1.00	0.0	162.9	0.144	0.152	150.70	7.70	492.50	48.83	19.57	19.74	0.047
1.00	0.98	86.5	0.0	0.077	0.079	51.90	3.40	495.90	49.17	15.26	23.24	0.039
1.00	1.00	0.0	200.3	0.177	0.519	144.90	6.80	502.70	49.84	21.31	76.32	0.034
1.00	1.00	0.0	159.5	0.141	0.426	153.90	5.90	508.60	50.43	26.08	72.20	0.037
0.98	0.93	91.7	0.0	0.081	0.143	57.00	3.80	512.40	50.81	15.00	37.63	0.041
1.00	1.00	0.0	179.1	0.159	0.430	124.00	6.00	518.40	51.40	20.67	71.67	0.033
1.00	1.00	0.0	180.1	0.159	0.209	171.80	4.30	522.70	51.83	39.95	48.60	0.024
0.10	0.10	0.0	0.0	0.0	1.135	123.90	37.41	560.11	55.54	6.60	78.82	

TABLE A5

RESULTS OF RUN LC5

[0.89 HCPV CO2 @ 1.00 MPa (0.39 g-mol) 4:1 WAG, 5-Slugs]

Porosity [%] = 35.6
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 17.10

Pore Volume [cm3] = 1107.8
Initial Oil Saturation [%] = 90.1
Hydrocarbon Pore Volume [cm3] = 998.1
Carbon Dioxide Retention [%inj] = 2.92

Connate Water Saturation [%] = 9.9
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 10.8000
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.00	1.00	180.0	0.0	0.162	0.0	0.0	28.80	28.80	2.89	0.0	0.0	0.160
1.00	0.92	0.0	219.7	0.198	0.490	38.10	143.90	172.70	17.30	0.26	3.41	0.655
1.18	1.04	0.0	171.5	0.155	0.208	106.90	62.30	235.00	23.54	1.72	3.34	0.363
1.16	1.04	0.0	189.7	0.171	0.241	140.00	48.20	283.20	28.37	2.90	5.00	0.254
1.06	0.95	0.0	139.0	0.125	0.131	118.00	22.90	306.10	30.67	5.15	5.72	0.165
1.00	0.98	180.0	0.0	0.162	0.040	45.20	11.10	317.20	31.78	4.07	3.60	0.062
1.04	1.00	0.0	205.8	0.186	0.325	143.90	18.10	335.30	33.59	7.95	17.96	0.088
1.18	1.08	0.0	208.9	0.189	0.217	187.90	20.90	356.20	35.69	8.99	10.38	0.100
1.12	1.04	0.0	187.7	0.169	0.233	168.00	20.00	376.20	37.69	8.40	11.65	0.107
0.94	0.87	0.0	119.3	0.108	0.180	101.40	22.50	398.70	39.94	4.51	8.00	0.189
1.00	0.93	180.0	0.0	0.162	0.035	63.40	9.20	407.90	40.87	6.89	3.80	0.051
1.11	1.07	0.0	255.8	0.231	0.410	176.00	15.40	423.30	42.41	11.43	26.62	0.060
0.98	0.96	0.0	202.6	0.183	0.554	192.70	11.20	434.50	43.53	17.21	49.46	0.055
1.04	1.00	0.0	211.5	0.191	0.598	201.60	12.20	446.70	44.75	16.52	49.02	0.058
1.04	1.01	0.0	51.6	0.047	0.118	49.40	4.00	450.70	45.15	12.35	29.50	0.077
1.00	0.94	180.0	0.0	0.162	0.102	67.00	5.60	456.30	45.72	11.96	18.21	0.031
1.07	1.02	0.0	249.7	0.225	0.498	179.90	9.90	466.20	46.71	18.17	50.30	0.040

TABLE A5 (CONTINUED)

RESULTS OF RUN LC5
[0.89 HCPV CO2 @ 1.00 MPa (0.39 g-mol) 4:1 WAG, 5-Slugs]

Porosity [%] = 35.6
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 17.10

Pore Volume [cm3] = 1107.8
Initial Oil Saturation [%] = 90.1
Hydrocarbon Pore Volume [cm3] = 998.1
Carbon Dioxide Retention [%inj] = 2.92

Connate Water Saturation [%] = 9.9
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 10.8000
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.04	1.00	0.0	199.7	0.180	0.569	190.10	8.50	474.70	47.56	22.36	66.94	0.043
1.06	1.01	0.0	209.5	0.189	0.628	199.70	10.10	484.80	48.57	19.77	62.18	0.048
1.05	1.00	0.0	61.7	0.056	0.192	61.00	3.90	488.70	48.96	15.64	49.23	0.063
1.00	0.96	180.0	0.0	0.162	0.161	65.40	12.70	501.40	50.23	5.15	12.68	0.071
1.00	1.00	0.0	260.6	0.235	0.662	188.00	8.00	509.40	51.04	23.50	82.75	0.031
1.00	1.00	0.0	204.4	0.185	0.600	195.80	8.10	517.50	51.85	24.17	74.07	0.040
1.00	1.00	0.0	178.2	0.161	0.526	171.80	5.90	523.40	52.44	29.12	89.15	0.033
1.00	1.00	0.0	76.6	0.069	0.254	74.10	3.90	527.30	52.83	19.00	65.13	0.051
0.10	0.10	0.0	0.0	0.0	1.116	97.00	10.30	537.60	53.86	4.78	54.98	

TABLE A6

RESULTS OF RUN LC6
[0.89 HCPV CO2 @ 1.00 MPa (0.39 g-mol) 4:1 WAG, 1-Slug]

Porosity [%] = 34.1
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 24.85

Pore Volume [cm3] = 1060.0
Initial Oil Saturation [%] = 89.2
Hydrocarbon Pore Volume [cm3] = 945.9
Carbon Dioxide Retention [%inj] = 5.97

Connate Water Saturation [%] = 10.8
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 12.7174
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.00	0.96	148.0	0.0	0.140	0.0	0.0	8.10	8.10	0.86	0.0	0.0	0.055
1.00	0.97	185.9	0.0	0.175	0.821	0.0	16.90	25.00	2.64	0.0	48.58	0.091
1.00	0.96	714.0	0.0	0.674	6.399	1.66	22.70	47.70	5.04	0.07	281.89	0.032
1.19	1.08	0.0	231.1	0.218	1.027	62.00	111.92	159.62	16.87	0.55	9.18	0.484
1.11	1.06	0.0	166.7	0.157	0.383	107.71	58.72	218.34	23.08	1.83	6.52	0.352
1.09	1.00	0.0	200.4	0.189	0.475	150.00	51.80	270.14	28.56	2.90	9.17	0.258
1.08	1.01	0.0	195.0	0.184	0.241	158.10	35.84	305.98	32.35	4.41	6.72	0.184
1.06	0.98	0.0	179.3	0.169	0.191	156.62	23.49	329.47	34.83	6.67	8.13	0.131
1.03	0.98	0.0	191.9	0.181	0.116	173.94	19.83	349.30	36.93	8.77	5.85	0.103
1.10	1.04	0.0	210.1	0.198	0.087	194.00	17.59	366.89	38.79	11.03	4.95	0.084
1.12	1.06	0.0	190.8	0.180	0.072	179.91	14.06	380.95	40.27	12.80	5.12	0.074
1.00	0.95	0.0	179.4	0.169	0.087	168.00	13.12	394.07	41.66	12.80	6.63	0.073
1.04	1.00	0.0	179.1	0.169	0.022	171.00	11.16	405.23	42.84	15.32	1.97	0.062
1.07	1.03	0.0	212.4	0.200	0.090	205.76	8.46	413.69	43.73	24.32	10.64	0.040
1.04	1.00	0.0	191.5	0.181	0.090	183.98	8.02	421.71	44.58	22.94	11.22	0.042
1.07	1.02	0.0	242.7	0.229	0.117	206.96	8.95	430.66	45.53	23.12	13.07	0.037
1.01	1.00	0.0	69.2	0.065	0.033	68.01	4.87	435.53	46.04	13.97	6.78	0.070

TABLE A6 (CONTINUED)

RESULTS OF RUN LC6
[0.89 HCPV CO2 @ 1.00 MPa (0.39 g-mol) 4:1 WAG, 1-Slug]

Porosity [%] = 34.1
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 24.85

Pore Volume [cm3] = 1060.0
Initial Oil Saturation [%] = 89.2
Hydrocarbon Pore Volume [cm3] = 945.9
Carbon Dioxide Retention [%inj] = 5.97

Connate Water Saturation [%] = 10.8
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 12.7174
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
0.10	0.10	0.0	0.0	0.0	0.0	2.21	3.14	438.67	46.37	0.70	0.0	

TABLE A7

RESULTS OF RUN LC7
[0.20 HCPV CO2 @ 1.00 MPa (0.08 g-mol) 4:1 WAG, 10-Slugs]

Porosity [%] = 34.8
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.44

Pore Volume [cm3] = 1082.0
Initial Oil Saturation [%] = 90.6
Hydrocarbon Pore Volume [cm3] = 980.1
Carbon Dioxide Retention [%inj] = 8.37

Connate Water Saturation [%] = 9.4
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 15.7743
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.00	0.95	19.6	0.0	0.018	0.0	0.0	0.10	0.10	0.01	0.0	0.0	0.005
1.38	1.10	0.0	83.7	0.077	0.040	0.0	61.00	61.10	6.23	0.0	0.66	0.728
1.00	0.94	19.6	0.0	0.018	0.0	0.0	12.00	73.10	7.46	0.0	0.0	0.612
1.12	0.96	0.0	78.4	0.072	0.038	15.50	56.50	129.60	13.22	0.27	0.67	0.721
1.00	0.99	19.6	0.0	0.018	0.0	4.50	8.40	138.00	14.08	0.54	0.0	0.429
1.24	1.08	0.0	78.4	0.072	0.030	31.50	40.00	178.00	18.16	0.79	0.75	0.510
1.00	1.00	19.6	0.0	0.018	0.0	5.10	6.80	184.80	18.86	0.75	0.0	0.347
1.22	1.14	0.0	78.4	0.072	0.035	42.10	30.40	215.20	21.96	1.38	1.15	0.388
1.00	1.04	20.2	0.0	0.019	0.0	3.00	4.90	220.10	22.46	0.61	0.0	0.243
1.24	1.16	0.0	78.5	0.073	0.042	48.00	25.90	246.00	25.10	1.85	1.62	0.330
1.00	1.02	19.6	0.0	0.018	0.003	10.00	6.00	252.00	25.71	1.67	0.50	0.306
1.02	0.94	0.0	78.4	0.072	0.041	49.20	18.30	270.30	27.58	2.69	2.24	0.233
1.00	0.94	19.6	0.0	0.018	0.0	8.00	4.00	274.30	27.99	2.00	0.0	0.204
1.19	1.09	0.0	78.4	0.072	0.040	55.90	15.00	289.30	29.52	3.73	2.67	0.191
1.00	0.96	19.6	0.0	0.018	0.0	11.00	3.90	293.20	29.92	2.82	0.0	0.199
1.32	1.24	0.0	78.5	0.073	0.050	53.70	11.60	304.80	31.10	4.63	4.31	0.148
1.00	0.95	19.6	0.0	0.018	0.0	11.50	3.50	308.30	31.46	3.29	0.0	0.179

TABLE A7 (CONTINUED)

RESULTS OF RUN LC7
[0.20 HCPV CO2 @ 1.00 MPa (0.08 g-mol) 4:1 WAG, 10-Slugs]

Porosity [%] = 34.8
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.44

Pore Volume [cm3] = 1082.0
Initial Oil Saturation [%] = 90.6
Hydrocarbon Pore Volume [cm3] = 980.1
Carbon Dioxide Retention [%inj] = 8.37

Connate Water Saturation [%] = 9.4
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 15.7743
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.02	0.90	0.0	78.4	0.072	0.066	57.00	11.00	319.30	32.58	5.18	6.00	0.140
1.00	0.98	19.6	0.0	0.018	0.014	14.00	3.50	322.80	32.94	4.00	4.00	0.179
1.20	1.12	0.0	78.4	0.072	0.078	54.50	9.50	332.30	33.91	5.74	8.21	0.121
1.16	1.09	0.0	209.1	0.193	0.229	185.80	21.10	353.40	36.06	8.81	10.85	0.101
1.10	1.00	0.0	235.5	0.218	0.257	220.60	21.60	375.00	38.26	10.21	11.90	0.092
1.20	1.08	0.0	227.6	0.210	0.182	210.70	15.40	390.40	39.83	13.68	11.82	0.068
1.20	1.13	0.0	219.5	0.203	0.119	207.20	13.70	404.10	41.23	15.12	8.69	0.062
1.09	1.06	0.0	442.9	0.409	0.254	415.00	22.30	426.40	43.51	18.61	11.39	0.050
1.12	1.06	0.0	487.9	0.451	0.293	475.10	19.80	446.20	45.53	23.99	14.80	0.041
1.18	1.06	0.0	245.8	0.227	0.052	235.80	10.80	457.00	46.63	21.83	4.81	0.044
0.10	0.10	0.0	0.0	0.0	0.011	9.60	3.30	460.30	46.97	2.91	3.33	

TABLE A8

RESULTS OF RUN LC8(a,b)
[2.11 HCPV WF => 0.20 RHCPV CO2 @ 1.00 MPa (0.05 g-mol) 4:1 WAG]

Porosity [%] = 37.1
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 2.77

Pore Volume [cm3] = 1152.0
Initial Oil Saturation [%] = 89.7
Hydrocarbon Pore Volume [cm3] = 1032.2
Carbon Dioxide Retention [%inj] = 55.63

Connate Water Saturation [%] = 10.3
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 11.3792
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.00	1.00	0.0	103.4	0.090	0.0	1.90	87.10	87.10	8.44	0.02	0.0	0.842
1.00	1.00	0.0	218.9	0.190	0.0	73.75	149.25	236.35	22.90	0.49	0.0	0.682
1.00	1.00	0.0	241.9	0.210	0.0	189.17	53.83	290.18	28.11	3.51	0.0	0.223
1.02	1.00	0.0	248.0	0.215	0.0	222.62	28.38	318.56	30.86	7.84	0.0	0.114
1.00	1.00	0.0	235.7	0.205	0.0	216.45	20.55	339.11	32.85	10.53	0.0	0.087
1.00	1.00	0.0	257.0	0.223	0.0	240.34	15.66	354.77	34.37	15.35	0.0	0.061
1.02	1.00	0.0	241.9	0.210	0.0	232.47	12.53	367.30	35.58	18.55	0.0	0.052
1.00	1.00	0.0	253.5	0.220	0.0	244.30	13.70	381.00	36.91	17.83	0.0	0.054
1.00	1.00	0.0	229.9	0.200	0.0	222.30	13.70	394.70	38.24	16.23	0.0	0.060
1.00	1.00	0.0	154.5	0.134	0.0	154.13	5.87	400.57	38.81	26.26	0.0	0.038
1.00	0.98	12.6	0.0	0.011	0.010	7.90	1.30	401.87	38.93	6.08	7.69	0.103
1.00	1.00	0.0	49.1	0.043	0.022	45.50	9.23	411.10	39.83	4.93	2.38	0.188
1.00	1.00	12.6	0.0	0.011	0.006	8.70	1.20	412.30	39.94	7.25	5.00	0.095
1.04	1.00	0.0	49.1	0.043	0.014	35.00	2.52	414.82	40.19	13.89	5.56	0.051
1.00	1.00	12.6	0.0	0.011	0.002	8.90	0.90	415.72	40.27	9.89	2.22	0.071
1.02	1.00	0.0	49.1	0.043	0.014	41.90	1.71	417.43	40.44	24.50	8.19	0.035
1.00	1.00	12.6	0.0	0.011	0.001	6.30	1.10	418.53	40.55	5.73	0.91	0.087

TABLE A8 (CONTINUED)

RESULTS OF RUN LC8(a,b)
[2.11 HCPV WF => 0.20 RHCPV CO2 @ 1.00 MPa (0.05 g-mol) 4:1 WAG]

Porosity [%] = 37.1
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 2.77

Pore Volume [cm3] = 1152.0
Initial Oil Saturation [%] = 89.7
Hydrocarbon Pore Volume [cm3] = 1032.2
Carbon Dioxide Retention [%inj] = 55.63

Connate Water Saturation [%] = 10.3
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 11.3792
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.00	1.00	0.0	49.1	0.043	0.024	46.90	2.03	420.56	40.74	23.10	11.82	0.041
1.00	1.00	12.6	0.0	0.011	0.004	7.80	1.20	421.76	40.86	6.50	3.33	0.095
1.00	1.00	0.0	49.1	0.043	0.020	46.20	1.66	423.42	41.02	27.83	12.05	0.034
1.00	1.00	12.6	0.0	0.011	0.004	10.00	1.20	424.62	41.14	8.33	3.33	0.095
1.00	1.00	0.0	49.1	0.043	0.008	31.00	1.77	426.39	41.31	17.51	4.52	0.036
1.00	1.00	12.6	0.0	0.011	0.009	13.90	1.00	427.39	41.40	13.90	9.00	0.079
1.00	1.00	0.0	49.1	0.043	0.011	37.00	2.60	429.99	41.66	14.23	4.23	0.053
1.00	1.00	12.6	0.0	0.011	0.006	10.70	0.80	430.79	41.73	13.37	7.50	0.063
1.00	1.00	0.0	49.1	0.043	0.012	35.00	1.54	432.33	41.88	22.73	7.79	0.031
1.00	1.00	12.6	0.0	0.011	0.011	15.00	1.00	433.33	41.98	15.00	11.00	0.079
1.00	1.00	0.0	49.1	0.043	0.013	36.90	2.33	435.66	42.21	15.84	5.58	0.047
1.00	1.00	12.6	0.0	0.011	0.009	10.10	0.90	436.56	42.29	11.22	10.00	0.071
1.00	1.00	0.0	49.1	0.043	0.018	37.80	1.77	438.33	42.46	21.36	10.17	0.036
1.00	1.00	0.0	101.9	0.088	0.092	97.90	3.10	441.43	42.76	31.58	29.68	0.030
0.10	0.10	0.0	0.0	0.0	0.274	174.10	33.70	475.13	46.03	5.17	8.13	

TABLE A9

RESULTS OF RUN LC9

[0.10 HCPV CO2 @ 1.00 MPa (0.04 g-mol) 4:1 WAG, 10-Slugs]

Porosity [%] = 36.7
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 2.34

Pore Volume [cm3] = 1142.0
Initial Oil Saturation [%] = 90.0
Hydrocarbon Pore Volume [cm3] = 1028.3
Carbon Dioxide Retention [%inj] = 6.01

Connate Water Saturation [%] = 10.0
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 12.6672
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.00	0.80	10.3	0.0	0.009	0.0	0.0	0.01	0.01	0.00	0.0	0.0	0.001
1.40	1.00	0.0	41.1	0.036	0.0	0.0	32.50	32.51	3.16	0.0	0.0	0.791
1.00	0.90	10.3	0.0	0.009	0.0	0.0	6.50	39.01	3.79	0.0	0.0	0.632
1.50	1.00	0.0	41.2	0.036	0.010	0.0	39.75	78.76	7.66	0.0	0.25	0.966
1.00	1.00	10.3	0.0	0.009	0.0	0.0	5.50	84.26	8.19	0.0	0.0	0.534
1.40	1.00	0.0	41.2	0.036	0.011	0.0	39.50	123.76	12.04	0.0	0.28	0.959
1.00	1.00	10.3	0.0	0.009	0.0	0.0	8.25	132.01	12.84	0.0	0.0	0.802
1.20	1.00	0.0	41.2	0.036	0.009	0.0	33.50	165.51	16.10	0.0	0.27	0.814
1.00	0.90	10.4	0.0	0.009	0.0	0.0	7.00	172.51	16.78	0.0	0.0	0.674
1.20	1.00	0.0	41.2	0.036	0.007	0.0	29.50	202.01	19.65	0.0	0.24	0.716
1.00	1.00	10.3	0.0	0.009	0.0	0.0	0.50	202.51	19.69	0.0	0.0	0.049
1.20	1.00	0.0	41.2	0.036	0.008	16.10	25.15	227.66	22.14	0.64	0.32	0.610
1.00	1.00	10.3	0.0	0.009	0.0	4.50	3.30	230.96	22.46	1.36	0.0	0.321
1.20	1.00	0.0	41.1	0.036	0.012	23.20	13.55	244.51	23.78	1.71	0.89	0.330
1.00	1.00	10.3	0.0	0.009	0.0	6.20	3.60	248.11	24.13	1.72	0.0	0.350
1.10	1.00	0.0	41.1	0.036	0.011	25.50	10.00	258.11	25.10	2.55	1.10	0.243
1.00	1.00	10.3	0.0	0.009	0.0	5.50	2.40	260.51	25.34	2.29	0.0	0.233

TABLE A9 (CONTINUED)

RESULTS OF RUN LC9
[0.10 HCPV CO2 @ 1.00 MPa (0.04 g-mol) 4:1 WAG, 10-Slugs]

Porosity [%] = 36.7
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 2.34

Pore Volume [cm3] = 1142.0
Initial Oil Saturation [%] = 90.0
Hydrocarbon Pore Volume [cm3] = 1028.3
Carbon Dioxide Retention [%inj] = 6.01

Connate Water Saturation [%] = 10.0
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 12.6672
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	41.1	0.036	0.005	28.00	7.25	267.76	26.04	3.86	0.69	0.176
1.00	1.00	10.4	0.0	0.009	0.0	8.75	2.35	270.11	26.27	3.72	0.0	0.227
1.06	1.00	0.0	41.1	0.036	0.009	28.10	6.70	276.81	26.92	4.19	1.34	0.163
1.08	1.02	0.0	247.9	0.217	0.089	202.50	45.00	321.81	31.30	4.50	1.98	0.182
1.06	1.01	0.0	491.3	0.430	0.142	438.00	54.50	376.31	36.60	8.04	2.61	0.111
1.04	1.00	0.0	478.5	0.419	0.233	446.00	35.50	411.81	40.05	12.56	6.56	0.074
1.01	1.00	0.0	494.1	0.433	0.249	475.50	26.50	438.31	42.63	17.94	9.40	0.054
1.04	1.02	0.0	235.6	0.206	0.110	227.00	10.80	449.11	43.68	21.02	10.19	0.046
1.02	1.00	0.0	244.6	0.214	0.103	239.50	7.00	456.11	44.36	34.21	14.71	0.029
0.10	0.10	0.0	0.0	0.0	0.0	5.50	3.00	459.11	44.65	1.83	0.0	

TABLE A10

RESULTS OF RUN LC10
[0.40 HCPV CO2 @ 1.00 MPa (0.17 g-mol) 4:1 WAG, 10-Slugs]

Porosity [%] = 35.8
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 8.59

Pore Volume [cm3] = 1112.0
Initial Oil Saturation [%] = 88.9
Hydrocarbon Pore Volume [cm3] = 988.9
Carbon Dioxide Retention [%inj] = 9.19

Connate Water Saturation [%] = 11.1
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 10.9778
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.00	0.80	39.6	0.0	0.036	0.0	0.0	0.01	0.01	0.00	0.0	0.0	0.000
1.35	1.06	0.0	158.2	0.142	0.070	8.00	129.50	129.51	13.10	0.06	0.54	0.819
1.00	1.00	41.4	0.0	0.037	0.008	4.00	14.00	143.51	14.51	0.29	0.57	0.338
1.08	1.02	0.0	158.3	0.142	0.090	76.00	68.75	212.26	21.46	1.11	1.31	0.434
1.00	1.00	39.6	0.0	0.036	0.005	14.00	10.40	222.66	22.52	1.35	0.48	0.263
1.07	1.00	0.0	158.3	0.142	0.194	89.50	50.00	272.66	27.57	1.79	3.88	0.316
1.04	1.00	39.6	0.0	0.036	0.021	18.40	8.80	281.46	28.46	2.09	2.39	0.222
1.17	1.14	0.0	161.8	0.145	0.344	113.00	27.10	308.56	31.20	4.17	12.69	0.168
1.06	1.00	39.6	0.0	0.036	0.045	18.90	6.10	314.66	31.82	3.10	7.38	0.154
1.05	1.00	0.0	158.3	0.142	0.297	120.50	16.00	330.66	33.44	7.53	18.56	0.101
1.04	1.00	39.6	0.0	0.036	0.067	22.90	5.00	335.66	33.94	4.58	13.40	0.126
1.10	1.06	0.0	158.3	0.142	0.231	119.00	15.40	351.06	35.50	7.73	15.00	0.097
1.03	1.00	39.6	0.0	0.036	0.026	23.40	5.70	356.76	36.08	4.11	4.56	0.144
1.06	1.00	0.0	158.2	0.142	0.209	114.20	19.80	376.56	38.08	5.77	10.56	0.125
1.04	1.00	39.6	0.0	0.036	0.061	29.50	6.00	382.56	38.69	4.92	10.17	0.152
1.04	0.99	0.0	158.3	0.142	0.278	115.50	14.50	[illegible]7.06	40.15	7.97	19.17	0.092
1.00	1.00	39.6	0.0	0.036	0.045	29.00	4.50	[illegible].56	40.61	6.44	10.00	0.114

TABLE A10 (CONTINUED)

RESULTS OF RUN LC10
[0.40 HCPV CO2 @ 1.00 MPa (0.17 g-mol) 4:1 WAG, 10-Slugs]

Porosity [%] = 35.8
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 8.59

Pore Volume [cm3] = 1112.0
Initial Oil Saturation [%] = 88.9
Hydrocarbon Pore Volume [cm3] = 988.9
Carbon Dioxide Retention [%inj] = 9.19

Connate Water Saturation [%] = 11.1
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 10.9778
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	157.7	0.142	0.227	117.00	12.00	413.56	41.82	9.75	18.92	0.076
1.00	1.00	39.6	0.0	0.036	0.080	28.80	3.30	416.86	42.15	8.73	24.24	0.083
1.05	1.00	0.0	158.2	0.142	0.252	123.00	11.30	428.16	43.30	10.88	22.30	0.071
1.08	1.00	0.0	244.5	0.220	0.315	227.75	13.75	441.91	44.69	16.56	22.91	0.056
1.09	0.99	0.0	239.8	0.216	0.466	228.50	14.00	455.91	46.10	16.32	33.29	0.058
1.08	1.01	0.0	250.9	0.226	0.301	240.50	13.50	469.41	47.47	17.81	22.30	0.054
1.10	1.01	0.0	201.4	0.181	0.202	192.50	9.70	479.11	48.45	19.85	20.82	0.048
0.10	0.10	0.0	0.0	0.0	0.008	25.00	13.50	492.61	49.81	1.85	0.59	

TABLE A11

RESULTS OF RUN LC11
[0.20 HCPV CO2 @ 1.00 MPa (0.09 g-mol) 8:1 WAG, 10-Slugs]

Porosity [%] = 38.3
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.59

Pore Volume [cm3] = 1190.0
Initial Oil Saturation [%] = 89.9
Hydrocarbon Pore Volume [cm3] = 1070.4
Carbon Dioxide Retention [%inj] = 8.00

Connate Water Saturation [%] = 10.1
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 13.9979
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.00	1.00	21.4	0.0	0.018	0.0	0.0	0.01	0.01	0.00	0.0	0.0	0.000
1.05	1.00	0.0	171.3	0.144	0.890	1.00	160.50	160.51	15.00	0.01	5.55	0.937
1.00	1.00	21.4	0.0	0.018	0.0	0.50	7.50	168.01	15.70	0.07	0.0	0.350
1.30	1.00	0.0	171.3	0.144	0.079	86.00	78.50	246.51	23.03	1.10	1.01	0.458
1.00	1.00	21.4	0.0	0.018	0.0	2.00	2.75	249.26	23.29	0.73	0.0	0.128
1.00	1.00	0.0	171.3	0.144	0.082	132.20	31.30	280.56	26.21	4.22	2.62	0.183
1.00	1.00	21.4	0.0	0.018	0.0	8.75	3.00	283.56	26.49	2.92	0.0	0.140
1.00	1.00	0.0	171.3	0.144	0.080	134.50	25.50	309.06	28.87	5.27	3.14	0.149
1.00	1.00	21.4	0.0	0.018	0.0	7.50	1.75	310.81	29.04	4.29	0.0	0.082
1.10	1.00	0.0	171.3	0.144	0.089	144.50	20.00	330.81	30.91	7.22	4.45	0.117
1.00	1.00	21.4	0.0	0.018	0.001	11.90	2.10	332.91	31.10	5.67	0.48	0.098
1.10	1.00	0.0	171.4	0.144	0.080	143.50	16.00	348.91	32.60	8.97	5.00	0.093
1.00	1.00	21.4	0.0	0.018	0.0	14.90	2.35	351.26	32.82	6.34	0.0	0.110
1.00	1.00	0.0	171.3	0.144	0.063	141.00	13.50	364.76	34.08	10.44	4.67	0.079
1.04	1.00	21.4	0.0	0.018	0.0	12.20	2.05	366.81	34.27	5.95	0.0	0.096
1.00	1.00	0.0	171.2	0.144	0.064	147.50	16.00	382.81	35.76	9.22	4.00	0.093
1.00	1.00	21.4	0.0	0.018	0.0	8.90	1.60	384.41	35.91	5.56	0.0	0.075

TABLE A11 (CONTINUED)

RESULTS OF RUN LC11
[0.20 HCPV CO2 @ 1.00 MPa (0.09 g-mol) 8:1 WAG, 10-Slugs]

Porosity [%] = 38.3
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.59

Pore Volume [cm3] = 1190.0
Initial Oil Saturation [%] = 89.9
Hydrocarbon Pore Volume [cm3] = 1070.4
Carbon Dioxide Retention [%inj] = 8.00

Connate Water Saturation [%] = 10.1
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 13.9979
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.08	1.00	0.0	172.6	0.145	0.093	146.00	15.50	399.91	37.36	9.42	6.00	0.090
1.00	1.00	21.4	0.0	0.018	0.004	14.80	1.45	401.36	37.50	10.21	2.76	0.068
1.05	1.00	0.0	171.3	0.144	0.085	149.50	9.50	410.86	38.38	15.74	8.95	0.055
1.04	1.00	0.0	491.9	0.413	0.108	467.50	28.50	439.36	41.05	16.40	3.79	0.058
1.00	1.00	0.0	491.5	0.413	0.133	484.00	24.00	463.36	43.29	20.17	5.54	0.049
1.00	1.00	0.0	245.7	0.206	0.094	241.00	10.50	473.86	44.27	22.95	8.95	0.043
1.00	1.00	0.0	93.5	0.079	0.056	86.00	7.50	481.36	44.97	11.47	7.47	0.080
0.10	0.10	0.0	0.0	0.0	0.060	48.00	6.50	487.86	45.58	7.38	9.23	

TABLE A12

RESULTS OF RUN LC12
[0.20 HCPV CO2 @ 1.00 MPa (0.09 g-mol) 2:1 WAG, 10-Slugs]

Porosity [%] = 38.4
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.18

Pore Volume [cm3] = 1194.0
Initial Oil Saturation [%] = 90.8
Hydrocarbon Pore Volume [cm3] = 1084.6
Carbon Dioxide Retention [%inj] = 15.55

Connate Water Saturation [%] = 9.2
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 16.1560
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.00	1.00	21.7	0.0	0.018	0.0	0.0	0.01	0.01	0.00	0.0	0.0	0.000
1.60	1.04	0.0	44.0	0.037	0.012	0.0	50.00	50.01	4.61	0.0	0.24	1.136
1.14	1.10	21.7	0.0	0.018	0.001	0.0	15.25	65.26	6.02	0.0	0.07	0.702
1.10	1.00	0.0	43.4	0.036	0.008	2.00	27.75	93.01	8.58	0.07	0.29	0.639
1.00	1.00	21.7	0.0	0.018	0.0	3.00	11.75	104.76	9.66	0.26	0.0	0.541
1.20	1.02	0.0	43.5	0.036	0.010	9.50	21.50	126.26	11.64	0.44	0.47	0.495
1.01	1.00	21.7	0.0	0.018	0.001	5.20	8.30	134.56	12.41	0.63	0.12	0.382
1.50	1.20	0.0	43.4	0.036	0.006	15.20	17.90	152.46	14.06	0.85	0.34	0.412
1.00	1.00	21.7	0.0	0.018	0.0	5.30	8.60	161.06	14.85	0.62	0.0	0.396
1.22	1.10	0.0	43.4	0.036	0.005	13.00	21.50	182.56	16.83	0.60	0.23	0.495
1.00	1.00	21.7	0.0	0.018	0.0	5.20	5.80	188.36	17.37	0.90	0.0	0.267
1.10	1.00	0.0	43.4	0.036	0.016	15.00	19.50	207.86	19.16	0.77	0.82	0.449
1.00	1.00	21.7	0.0	0.018	0.001	5.90	7.10	214.96	19.82	0.83	0.14	0.327
1.04	1.00	0.0	40.4	0.034	0.010	17.90	13.60	228.56	21.07	1.32	0.74	0.337
1.01	1.00	21.7	0.0	0.018	0.001	9.20	5.80	234.36	21.61	1.59	0.17	0.267
1.02	1.00	0.0	44.0	0.037	0.010	23.50	10.50	244.86	22.58	2.24	0.95	0.238
1.00	1.00	21.7	0.0	0.018	0.0	11.00	4.00	248.86	22.94	2.75	0.0	0.184

TABLE A12 (CONTINUED)

RESULTS OF RUN LC12
[0.20 HCPV CO2 @ 1.00 MPa (0.09 g-mol) 2:1 WAG, 10-Slugs]

Porosity [%] = 38.4
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.18

Pore Volume [cm3] = 1194.0
Initial Oil Saturation [%] = 90.8
Hydrocarbon Pore Volume [cm3] = 1084.6
Carbon Dioxide Retention [%inj] = 15.55

Connate Water Saturation [%] = 9.2
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 16.1560
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	43.4	0.036	0.011	24.50	8.00	256.86	23.68	3.06	1.37	0.184
1.00	1.00	21.7	0.0	0.018	0.012	11.00	3.50	260.36	24.00	3.14	3.43	0.161
1.10	1.00	0.0	43.4	0.036	0.009	24.80	7.70	268.06	24.71	3.22	1.17	0.177
1.00	1.00	0.0	239.8	0.201	0.139	192.00	49.75	317.81	29.30	3.86	2.79	0.207
1.00	1.00	0.0	493.3	0.413	0.746	471.50	38.50	356.31	32.85	12.25	19.38	0.078
1.04	1.00	0.0	490.9	0.411	0.477	473.50	30.00	386.31	35.62	15.78	15.90	0.061
1.00	1.00	0.0	444.0	0.372	0.252	422.50	22.00	408.31	37.65	19.20	11.45	0.050
1.00	1.00	0.0	408.6	0.342	0.213	386.00	25.00	433.31	39.95	15.44	8.52	0.061
0.10	0.10	0.0	0.0	0.0	0.001	24.00	10.00	443.31	40.87	2.40	0.10	

TABLE A13

RESULTS OF RUN LC13
[0.20 HCPV CO2 @ 1.00 MPa (0.09 g-mol) 4:1 WAG, 10-Slugs]

Porosity [%] = 36.2
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.63

Pore Volume [cm3] = 1126.0
Initial Oil Saturation [%] = 90.5
Hydrocarbon Pore Volume [cm3] = 1019.1
Carbon Dioxide Retention [%inj] = 53.31

Connate Water Saturation [%] = 9.5
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 12.1176
Average Flow Velocity [m/d] = 0.492

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.00	1.00	20.4	0.0	0.018	0.0	0.0	0.01	0.01	0.00	0.0	0.0	0.000
1.30	1.00	0.0	81.5	0.072	0.0	0.0	71.50	71.51	7.02	0.0	0.0	0.877
1.00	1.00	20.4	0.0	0.018	0.0	0.0	10.25	81.76	8.02	0.0	0.0	0.503
1.20	1.00	0.0	81.5	0.072	0.0	0.0	75.75	157.51	15.46	0.0	0.0	0.929
1.00	1.00	20.4	0.0	0.018	0.0	0.50	12.50	170.01	16.68	0.04	0.0	0.613
1.00	1.00	0.0	81.6	0.072	0.005	22.50	49.75	219.76	21.56	0.45	0.10	0.610
1.00	1.00	20.4	0.0	0.018	0.0	6.10	7.90	227.66	22.34	0.77	0.0	0.388
1.08	1.00	0.0	81.5	0.072	0.009	39.75	31.50	259.16	25.43	1.26	0.29	0.386
1.00	1.00	20.4	0.0	0.018	0.0	9.75	5.75	264.91	25.99	1.70	0.0	0.282
1.10	1.00	0.0	81.5	0.072	0.005	48.75	17.25	282.16	27.69	2.83	0.29	0.212
1.00	1.00	20.4	0.0	0.018	0.0	10.75	3.00	285.16	27.98	3.58	0.0	0.147
1.08	1.00	0.0	81.6	0.072	0.0	59.00	12.00	297.16	29.16	4.92	0.0	0.147
1.00	1.00	20.4	0.0	0.018	0.0	9.80	2.70	299.86	29.42	3.63	0.0	0.132
1.04	1.00	0.0	81.6	0.072	0.012	61.20	12.05	311.91	30.61	5.08	1.00	0.148
1.00	1.00	20.4	0.0	0.018	0.0	13.75	2.75	314.66	30.88	5.00	0.0	0.135
1.02	1.00	0.0	81.4	0.072	0.014	60.00	9.20	323.86	31.78	6.52	1.52	0.113
1.00	1.00	20.4	0.0	0.018	0.0	13.90	2.85	326.71	32.06	4.88	0.0	0.140

TABLE A13 (CONTINUED)

RESULTS OF RUN LC13
[0.20 HCPV CO2 @ 1.00 MPa (0.09 g-mol) 4:1 WAG, 10-Slugs]

Porosity [%] = 36.2
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.63

Pore Volume [cm3] = 1126.0
Initial Oil Saturation [%] = 90.5
Hydrocarbon Pore Volume [cm3] = 1019.1
Carbon Dioxide Retention [%inj] = 53.31

Connate Water Saturation [%] = 9.5
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 12.1176
Average Flow Velocity [m/d] = 0.492

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.03	1.00	0.0	81.5	0.072	0.004	60.50	8.50	335.21	32.89	7.12	0.47	0.104
1.00	1.00	20.4	0.0	0.018	0.0	13.25	2.25	337.46	33.11	5.89	0.0	0.110
1.00	1.00	0.0	81.7	0.073	0.013	61.95	8.80	346.26	33.98	7.04	1.48	0.108
1.00	1.00	0.0	480.6	0.427	0.077	439.50	49.50	395.76	38.83	8.88	1.56	0.103
1.00	1.00	0.0	490.8	0.436	0.429	468.00	31.00	426.76	41.87	15.10	13.84	0.063
1.00	1.00	0.0	496.9	0.441	0.392	480.00	20.00	446.76	43.84	24.00	19.60	0.040
1.00	1.00	0.0	8.2	0.007	0.020	3.00	1.00	447.76	43.94	3.00	20.00	0.122
0.10	0.10	0.0	0.0	0.0	0.010	18.50	10.00	457.76	44.92	1.85	1.00	

TABLE A14

RESULTS OF RUN LC14
[0.20 HCPV CO2 @ 1.00 MPa (0.09 g-mol) 8:1 WAG, 10-Slugs]

Porosity [%] = 36.9
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.65

Pore Volume [cm3] = 1148.0
Initial Oil Saturation [%] = 90.2
Hydrocarbon Pore Volume [cm3] = 1035.7
Carbon Dioxide Retention [%inj] = 57.78

Connate Water Saturation [%] = 9.8
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 12.0468
Average Flow Velocity [m/d] = 0.492

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.00	1.00	20.8	0.0	0.018	0.0	0.0	0.01	0.01	0.00	0.0	0.0	0.000
1.26	1.00	0.0	165.7	0.144	0.082	0.0	160.00	160.01	15.45	0.0	0.51	0.965
1.00	1.00	20.8	0.0	0.018	0.002	0.0	12.10	172.11	16.62	0.0	0.17	0.583
1.20	1.00	0.0	165.5	0.144	0.068	62.20	91.80	263.91	25.48	0.68	0.74	0.555
1.00	1.00	20.8	0.0	0.018	0.003	12.00	6.50	270.41	26.11	1.85	0.46	0.313
1.20	1.00	0.0	165.8	0.144	0.053	121.50	28.00	298.41	28.81	4.34	1.89	0.169
1.00	1.00	20.8	0.0	0.018	0.001	12.90	2.10	300.51	29.01	6.14	0.48	0.101
1.00	1.00	0.0	165.7	0.144	0.045	139.00	14.80	315.31	30.44	9.39	3.04	0.089
1.00	1.00	20.8	0.0	0.018	0.0	14.90	1.90	317.21	30.63	7.84	0.0	0.092
1.10	1.00	0.0	166.1	0.145	0.034	138.50	13.50	330.71	31.93	10.26	2.52	0.081
1.00	1.00	20.8	0.0	0.018	0.001	14.30	2.20	332.91	32.14	6.50	0.45	0.106
1.04	1.00	0.0	165.7	0.144	0.029	138.20	15.30	348.21	33.62	9.03	1.90	0.092
1.00	1.00	20.8	0.0	0.018	0.0	15.50	2.00	350.21	33.81	7.75	0.0	0.096
1.00	1.00	0.0	165.7	0.144	0.019	135.80	14.20	364.44	35.18	9.56	1.34	0.086
1.00	1.00	20.8	0.0	0.018	0.001	13.90	1.90	366.31	35.37	7.32	0.53	0.092
1.08	1.00	0.0	165.8	0.144	0.040	143.80	14.20	380.51	36.74	10.13	2.82	0.086
1.00	1.00	20.8	0.0	0.018	0.0	12.50	2.50	383.01	36.98	5.00	0.0	0.120

TABLE A14 (CONTINUED)

RESULTS OF RUN LC14
[0.20 HCPV CO2 @ 1.00 MPa (0.09 g-mol) 8:1 WAG, 10-Slugs]

Porosity [%] = 36.9
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.65

Pore Volume [cm3] = 1148.0
Initial Oil Saturation [%] = 90.2
Hydrocarbon Pore Volume [cm3] = 1035.7
Carbon Dioxide Retention [%inj] = 57.78

Connate Water Saturation [%] = 9.8
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 12.0468
Average Flow Velocity [m/d] = 0.492

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.07	1.00	0.0	165.7	0.144	0.071	141.00	10.50	393.51	37.99	13.43	6.76	0.063
1.00	1.00	20.8	0.0	0.018	0.001	14.90	1.90	395.41	38.18	7.84	0.53	0.092
1.00	1.00	0.0	165.8	0.144	0.004	153.50	12.00	407.41	39.34	12.79	0.33	0.072
1.00	1.00	0.0	497.6	0.433	0.204	468.00	23.00	430.41	41.56	20.35	8.87	0.046
1.00	1.00	0.0	456.3	0.397	0.220	436.50	18.50	448.91	43.34	23.59	11.89	0.041
0.10	0.10	0.0	0.0	0.0	0.034	62.00	16.00	464.91	44.89	3.88	2.13	

TABLE A15

RESULTS OF RUN LC15
[0.20 HCPV CO2 @ 1.00 MPa (0.09 g-mol) 2:1 WAG, 10-Slugs]

Porosity [%] = 36.6
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.74

Pore Volume [cm3] = 1137.0
Initial Oil Saturation [%] = 90.3
Hydrocarbon Pore Volume [cm3] = 1026.5
Carbon Dioxide Retention [%inj] = 23.51

Connate Water Saturation [%] = 9.7
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 12.0556
Average Flow Velocity [m/d] = 0.492

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.00	1.00	20.6	0.0	0.018	0.0	0.0	0.10	0.10	0.01	0.0	0.0	0.005
1.30	1.00	0.0	41.1	0.036	0.0	0.0	32.00	32.10	3.13	0.0	0.0	0.779
1.00	1.00	20.6	0.0	0.018	0.0	0.0	11.20	43.30	4.22	0.0	0.0	0.544
1.16	1.00	0.0	41.1	0.036	0.0	0.0	35.00	78.30	7.63	0.0	0.0	0.852
1.00	1.00	20.6	0.0	0.018	0.0	0.0	13.50	91.80	8.94	0.0	0.0	0.656
1.20	1.00	0.0	41.1	0.036	0.0	0.0	32.50	124.30	12.11	0.0	0.0	0.791
1.00	1.00	20.6	0.0	0.018	0.0	0.0	13.00	137.30	13.38	0.0	0.0	0.632
1.16	1.00	0.0	41.1	0.036	0.0	3.00	29.00	166.30	16.20	0.10	0.0	0.706
1.00	1.00	20.6	0.0	0.018	0.0	3.50	10.75	177.05	17.25	0.33	0.0	0.523
1.10	1.00	0.0	41.1	0.036	0.0	10.75	26.75	203.80	19.85	0.40	0.0	0.651
1.00	1.00	20.6	0.0	0.018	0.0	4.00	9.75	213.55	20.80	0.41	0.0	0.474
1.10	1.00	0.0	41.1	0.036	0.0	9.80	15.20	228.75	22.28	0.64	0.0	0.370
1.00	1.00	20.6	0.0	0.018	0.0	6.90	6.35	235.10	22.90	1.09	0.0	0.309
1.00	1.00	0.0	41.0	0.036	0.0	14.00	14.25	249.35	24.29	0.98	0.0	0.347
1.00	1.00	20.6	0.0	0.018	0.0	9.00	7.00	256.35	24.97	1.29	0.0	0.340
1.10	1.00	0.0	41.1	0.036	0.0	18.80	10.70	267.05	26.02	1.76	0.0	0.261
1.00	1.00	20.6	0.0	0.018	0.0	11.00	5.80	272.85	26.58	1.90	0.0	0.282

TABLE A15 (CONTINUED)

RESULTS OF RUN LC15
[0.20 HCPV CO2 @ 1.00 MPa (0.09 g-mol) 2:1 WAG, 10-Slugs]

Porosity [%] = 36.6
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.74

Pore Volume [cm3] = 1137.0
Initial Oil Saturation [%] = 90.3
Hydrocarbon Pore Volume [cm3] = 1026.5
Carbon Dioxide Retention [%inj] = 23.51

Connate Water Saturation [%] = 9.7
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 12.0556
Average Flow Velocity [m/d] = 0.492

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.00	1.00	0.0	41.1	0.036	0.0	17.50	9.00	281.85	27.46	1.94	0.0	0.219
1.00	1.00	20.6	0.0	0.018	0.0	13.50	5.10	286.95	27.95	2.65	0.0	0.248
1.00	1.00	0.0	41.0	0.036	0.0	22.00	5.50	292.45	28.49	4.00	0.0	0.134
1.00	1.00	0.0	248.3	0.218	0.095	201.50	43.50	335.95	32.73	4.63	2.18	0.175
1.00	1.00	0.0	498.7	0.439	0.400	443.50	56.50	392.45	38.23	7.85	7.08	0.113
1.00	1.00	0.0	491.1	0.432	0.433	463.00	31.00	423.45	41.25	14.94	13.97	0.063
1.00	1.00	0.0	499.3	0.439	0.680	483.00	20.00	443.45	43.20	24.15	34.00	0.040
0.10	0.10	0.0	0.0	0.0	0.029	37.00	8.00	451.45	43.98	4.63	3.62	

TABLE A16

RESULTS OF RUN LC16
[0.64 HCPV CO2 @ 2.50 MPa (0.75 g-mol) 4:1 WAG. 10-Slugs]

Porosity [%] = 34.8
Oil Viscosity [mPa.s] = 1059.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 29.71

Pore Volume [cm3] = 1080.0
Initial Oil Saturation [%] = 79.1
Hydrocarbon Pore Volume [cm3] = 967.8
Carbon Dioxide Retention [%inj] = 93.91

Connate Water Saturation [%] = 20.9
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 9.0246
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
2.65	2.46	53.0	0.0	0.049	0.0	0.0	5.00	5.00	0.52	0.0	0.0	0.094
2.61	2.35	0.0	174.1	0.161	0.0	18.00	144.00	149.00	15.40	0.13	0.0	0.827
2.50	2.30	0.0	39.1	0.036	0.0	17.00	24.90	173.90	17.97	0.68	0.0	0.637
2.38	2.30	53.0	0.0	0.049	0.0	23.00	22.00	195.90	20.24	1.05	0.0	0.415
2.45	2.40	0.0	133.2	0.123	0.0	87.00	47.01	242.91	25.10	1.85	0.0	0.353
2.45	2.40	0.0	84.3	0.078	0.0	65.50	18.50	261.41	27.01	3.54	0.0	0.220
2.42	2.40	53.0	0.0	0.049	0.0	29.00	9.00	270.41	27.94	3.22	0.0	0.170
2.47	2.46	0.0	127.1	0.118	0.060	84.00	19.00	289.41	29.90	4.42	3.16	0.150
2.45	2.44	0.0	85.0	0.079	0.001	72.00	14.00	303.41	31.35	5.14	0.07	0.165
2.40	2.40	53.8	0.0	0.050	0.034	39.00	8.00	311.41	32.18	4.88	4.25	0.149
2.48	2.45	0.0	215.2	0.199	0.050	160.00	19.00	330.41	34.14	8.42	2.63	0.088
2.46	2.45	52.9	0.0	0.049	0.001	15.50	16.50	346.91	35.84	0.94	0.06	0.312
2.50	2.48	0.0	211.8	0.196	0.0	170.00	18.00	364.91	37.70	9.44	0.0	0.085
2.50	2.50	52.2	0.0	0.048	0.009	27.00	4.00	368.91	38.12	6.75	2.25	0.077
2.48	2.47	0.0	139.1	0.129	0.0	106.00	8.00	376.91	38.94	13.25	0.0	0.057
2.48	2.47	0.0	77.0	0.071	0.0	70.50	6.50	383.41	39.62	10.85	0.0	0.084
2.50	2.50	53.6	0.0	0.050	0.003	27.50	5.50	388.91	40.18	5.00	0.55	0.103

TABLE A16 (CONTINUED)

RESULTS OF RUN LC16
[0.64 HCPV CO2 @ 2.50 MPa (0.75 g-mol) 4:1 WAG, 10-Slugs]

Porosity [%] = 34.8
Oil Viscosity [mPa.s] = 1059.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 29.71

Pore Volume [cm3] = 1080.0
Initial Oil Saturation [%] = 79.1
Hydrocarbon Pore Volume [cm3] = 967.8
Carbon Dioxide Retention [%inj] = 93.91

Connate Water Saturation [%] = 20.9
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 9.0246
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
2.53	2.51	0.0	189.0	0.175	0.0	150.00	12.00	400.91	41.42	12.50	0.0	0.063
2.52	2.49	0.0	24.0	0.022	0.0	23.00	5.00	405.91	41.94	4.60	0.0	0.208
2.52	2.52	52.8	0.0	0.049	0.0	27.50	4.50	410.41	42.41	6.11	0.0	0.085
2.50	2.50	0.0	155.9	0.144	0.0	118.00	8.00	418.41	43.23	14.75	0.0	0.051
2.50	2.50	0.0	57.5	0.053	0.001	51.50	1.50	419.91	43.39	34.33	0.67	0.026
2.50	2.50	49.9	0.0	0.046	0.001	29.50	3.50	423.41	43.75	8.43	0.29	0.070
2.51	2.51	0.0	214.8	0.199	0.0	177.00	9.00	432.41	44.68	19.67	0.0	0.042
2.46	2.45	55.5	0.0	0.051	0.020	58.00	3.00	435.41	44.99	19.33	6.67	0.054
2.51	2.50	0.0	154.8	0.143	0.062	128.00	10.00	445.41	46.02	12.80	6.20	0.065
2.54	2.53	0.0	47.9	0.044	0.0	45.50	3.50	448.91	46.38	13.00	0.0	0.073
2.53	2.52	0.0	65.0	0.060	0.001	62.00	4.00	452.91	46.80	15.50	0.25	0.062
2.50	2.48	0.0	379.5	0.351	0.0	364.50	16.50	469.41	48.50	22.09	0.0	0.043
2.49	2.49	0.0	50.0	0.046	0.0	46.55	3.45	472.86	48.86	13.49	0.0	0.069
2.44	2.42	0.0	89.9	0.083	0.0	85.80	8.20	481.06	49.71	10.46	0.0	0.091
2.52	2.50	0.0	50.3	0.047	0.0	48.73	2.27	483.33	49.94	21.47	0.0	0.045
0.10	0.10	0.0	0.0	0.0	0.508	84.00	10.50	493.83	51.02	8.00	48.38	
0.10	0.10	0.0	0.0	0.0	0.171	66.50	2.50	496.33	51.28	26.60	68.40	

TABLE A16 (CONTINUED)

RESULTS OF RUN LC16
[0.64 HCPV CO2 @ 2.50 MPa (0.75 g-mol) 4:1 WAG, 10-Slugs]

Porosity [%] = 34.8
Oil Viscosity [mPa.s] = 1059.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 29.71

Pore Volume [cm3] = 1080.0
Initial Oil Saturation [%] = 79.1
Hydrocarbon Pore Volume [cm3] = 967.8
Carbon Dioxide Retention [%inj] = 93.91

Connate Water Saturation [%] = 20.9
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 9.0246
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
0.10	0.10	0.0	0.0	0.0	0.001	64.00	14.00	510.33	52.73	4.57	0.07	

TABLE A17

RESULTS OF RUN LC17
[0.20 HCPV CO2 @ 2.50 MPa (0.26 g-mol) 4:1 WAG, 10-Slugs]

Porosity [%] = 37.7
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 12.64

Pore Volume [cm3] = 1172.0
Initial Oil Saturation [%] = 89.2
Hydrocarbon Pore Volume [cm3] = 996.7
Carbon Dioxide Retention [%inj] = 20.46

Connate Water Saturation [%] = 10.8
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 12.3036
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
2.50	2.20	20.9	0.0	0.018	0.0	0.0	0.10	0.10	0.01	0.0	0.0	0.005
3.00	2.53	0.0	83.7	0.071	0.060	0.0	73.00	73.10	7.33	0.0	0.82	0.872
2.50	2.00	20.9	0.0	0.018	0.001	0.0	1.00	74.10	7.43	0.0	1.00	0.048
2.84	2.50	0.0	83.7	0.071	0.072	21.00	56.50	130.60	13.10	0.37	1.27	0.675
2.50	2.50	20.9	0.0	0.018	0.004	5.50	8.60	139.20	13.97	0.64	0.47	0.411
2.64	2.54	0.0	83.7	0.071	0.051	45.50	37.25	176.45	17.70	1.22	1.37	0.445
2.50	2.50	20.9	0.0	0.018	0.002	6.75	5.75	182.20	18.28	1.52	0.35	0.275
2.64	2.54	0.0	83.7	0.071	0.028	43.00	20.00	202.20	20.29	2.15	1.40	0.239
2.50	2.50	20.9	0.0	0.018	0.011	18.75	7.15	209.35	21.00	2.62	1.54	0.342
2.60	2.54	0.0	83.7	0.071	0.024	44.75	18.75	228.10	22.89	2.39	1.28	0.224
2.50	2.50	20.9	0.0	0.018	0.013	17.90	9.00	237.10	23.79	1.99	1.44	0.430
2.62	2.52	0.0	83.7	0.071	0.031	43.90	18.60	255.70	25.66	2.36	1.67	0.222
2.50	2.54	20.9	0.0	0.018	0.013	7.80	4.20	259.90	26.08	1.86	3.10	0.201
2.64	2.52	0.0	83.7	0.071	0.068	58.90	22.60	282.50	28.34	2.61	3.01	0.270
2.50	2.52	20.9	0.0	0.018	0.021	18.10	6.80	289.30	29.03	2.66	3.09	0.325
2.60	2.51	0.0	83.7	0.071	0.168	43.00	17.00	306.30	30.73	2.53	9.88	0.203
2.50	2.50	20.9	0.0	0.018	0.054	15.00	5.50	311.80	31.28	2.73	9.82	0.263

TABLE A17 (CONTINUED)

RESULTS OF RUN LC17
[0.20 HCPV CO2 @ 2.50 MPa (0.26 g-mol) 4:1 WAG, 10-Slugs]

Porosity [%] = 37.7
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 12.64

Pore Volume [cm3] = 1172.0
Initial Oil Saturation [%] = 89.2
Hydrocarbon Pore Volume [cm3] = 996.7
Carbon Dioxide Retention [%inj] = 20.46

Connate Water Saturation [%] = 10.8
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 12.3036
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
2.58	2.48	0.0	83.7	0.071	0.116	15.00	5.50	317.30	31.84	2.73	21.09	0.066
2.50	2.50	20.9	0.0	0.018	0.038	18.80	5.10	322.40	32.35	3.69	7.45	0.244
2.61	2.52	0.0	83.8	0.071	0.283	49.90	15.20	337.60	33.87	3.28	18.62	0.181
2.66	2.50	0.0	499.1	0.426	1.454	432.00	63.00	400.60	40.19	6.86	23.08	0.126
2.58	2.51	0.0	486.9	0.415	1.258	452.50	33.50	434.10	43.55	13.51	37.55	0.069
2.60	2.50	0.0	489.4	0.418	0.665	477.00	21.00	455.10	45.66	22.71	31.67	0.043
0.10	0.10	0.0	0.0	0.0	0.375	226.00	23.50	478.60	48.02	9.62	15.96	

TABLE A18

RESULTS OF RUN LC18
[0.21 HCPV CO2 @ 5.50 MPa (0.74 g-mol) 4:1 WAG, 10-Slugs]

Porosity [%] = 33.3
Oil Viscosity [mPa.s] = 1059.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 43.43

Pore Volume [cm3] = 1035.2
Initial Oil Saturation [%] = 89.7
Hydrocarbon Pore Volume [cm3] = 938.8
Carbon Dioxide Retention [%inj] = 100.00

Connate Water Saturation [%] = 10.3
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 5.9116
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
5.87	5.43	19.0	75.0	0.091	0.0	0.0	65.50	65.50	6.98	0.0	0.0	0.697
5.72	5.36	18.9	49.5	0.066	0.0	0.0	50.00	115.50	12.30	0.0	0.0	0.730
5.67	5.37	0.0	25.5	0.025	0.0	6.20	21.30	136.80	14.57	0.29	0.0	0.837
5.66	5.41	19.3	70.5	0.087	0.0	36.63	34.37	171.17	18.23	1.07	0.0	0.383
5.60	5.39	19.0	80.0	0.096	0.0	55.50	27.50	198.67	21.16	2.02	0.0	0.278
5.70	5.46	19.1	75.0	0.091	0.0	55.00	22.00	220.67	23.51	2.50	0.0	0.234
5.63	5.40	18.8	75.0	0.091	0.0	58.00	19.50	240.17	25.58	2.97	0.0	0.208
5.59	5.40	19.2	75.0	0.091	0.0	59.75	16.25	256.42	27.31	3.68	0.0	0.173
5.60	5.41	19.1	74.9	0.091	0.0	63.75	14.75	271.17	28.88	4.32	0.0	0.157
5.73	5.50	19.1	75.0	0.091	0.0	63.00	13.50	284.67	30.32	4.67	0.0	0.144
5.62	5.44	20.1	75.8	0.093	0.0	66.50	11.00	295.67	31.49	6.05	0.0	0.115
5.54	5.36	0.0	181.9	0.176	0.0	163.50	20.00	315.67	33.62	8.17	0.0	0.110
5.50	5.39	0.0	74.8	0.072	0.0	70.50	7.50	323.17	34.42	9.40	0.0	0.100
5.50	5.38	0.0	114.1	0.110	0.0	170.00	9.50	332.67	35.43	17.89	0.0	0.083
5.53	5.34	0.0	113.1	0.109	0.0	106.00	8.50	341.17	36.34	12.47	0.0	0.075
5.50	5.30	0.0	92.9	0.090	0.0	85.50	8.50	349.67	37.25	10.06	0.0	0.092
5.50	5.35	0.0	158.4	0.153	0.0	148.25	11.75	361.42	38.50	12.62	0.0	0.074

TABLE A18 (CONTINUED)

RESULTS OF RUN LC18
[0.21 HCPV CO2 @ 5.50 MPa (0.74 g-mol) 4:1 WAG, 10-Slugs]

Porosity [%] = 33.3
Oil Viscosity [mPa.s] = 1059.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 43.43

Pore Volume [cm3] = 1035.2
Initial Oil Saturation [%] = 89.7
Hydrocarbon Pore Volume [cm3] = 938.8
Carbon Dioxide Retention [%inj] = 100.00

Connate Water Saturation [%] = 10.3
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 5.9116
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
5.61	5.43	0.0	134.5	0.130	0.0	127.00	9.50	370.92	39.51	13.37	0.0	0.071
5.36	5.12	0.0	344.3	0.333	0.0	328.50	30.50	401.42	42.76	10.77	0.0	0.089
5.46	5.25	0.0	129.3	0.125	0.0	123.50	3.50	404.92	43.13	35.29	0.0	0.027
5.50	5.40	0.0	127.0	0.123	0.0	122.50	4.50	409.42	43.61	27.22	0.0	0.035
5.51	5.40	0.0	100.6	0.097	0.0	132.20	5.80	415.22	44.23	22.79	0.0	0.058
5.50	5.27	0.0	110.6	0.107	0.0	108.10	3.40	418.62	44.59	31.79	0.0	0.031
5.50	5.40	0.0	40.9	0.040	0.0	40.95	4.55	423.17	45.07	9.00	0.0	0.111
5.50	5.30	0.0	178.1	0.172	0.0	173.90	5.10	428.27	45.62	34.10	0.0	0.029
5.46	5.20	0.0	148.8	0.144	0.0	146.80	4.20	432.47	46.07	34.95	0.0	0.028
5.55	5.40	0.0	75.8	0.073	0.0	75.50	2.00	434.47	46.28	37.75	0.0	0.026
0.10	0.10	0.0	0.0	0.0	0.0	25.00	5.00	439.47	46.81	5.00	0.0	

TABLE A19

RESULTS OF RUN LC19
[0.20 HCPV CO2 @ 5.50 MPa (0.70 g-mol) 4:1 WAG, 10-Slugs]

Porosity [%] = 34.4
Oil Viscosity [mPa.s] = 1059.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 44.76

Pore Volume [cm3] = 1062.0
Initial Oil Saturation [%] = 89.2
Hydrocarbon Pore Volume [cm3] = 957.5
Carbon Dioxide Retention [%inj] = 98.90

Connate Water Saturation [%] = 10.8
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 12.3631
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
5.83	5.03	19.1	76.6	0.090	0.0	0.0	64.00	64.00	6.68	0.0	0.0	0.669
5.50	4.95	20.7	80.3	0.095	0.0	5.10	78.90	142.90	14.92	0.06	0.0	0.782
5.62	5.14	19.4	78.5	0.092	0.0	34.10	52.90	195.80	20.45	0.64	0.0	0.540
5.52	5.18	19.3	80.4	0.094	0.0	37.90	48.10	243.90	25.47	0.79	0.0	0.482
5.70	5.28	19.1	76.6	0.090	0.0	58.88	21.12	265.02	27.68	2.79	0.0	0.221
5.54	5.23	23.9	76.6	0.095	0.050	59.80	18.20	283.22	29.58	3.29	2.75	0.181
5.53	5.25	29.1	73.7	0.097	0.071	58.85	15.15	298.37	31.16	3.88	4.69	0.147
5.51	5.25	12.9	73.7	0.081	0.041	64.00	8.50	306.87	32.05	7.53	4.82	0.098
5.50	5.25	13.5	76.6	0.085	0.019	65.10	10.90	317.77	33.19	5.97	1.74	0.121
5.55	5.20	14.7	73.1	0.083	0.018	64.60	8.40	326.17	34.06	7.69	2.14	0.096
5.55	5.35	0.0	111.7	0.105	0.003	102.60	6.40	332.57	34.73	16.03	0.47	0.057
5.40	5.21	0.0	132.9	0.125	0.0	115.70	17.30	349.87	36.54	6.69	0.0	0.130
5.50	5.30	0.0	112.2	0.106	0.0	108.87	5.13	355.00	37.08	21.22	0.0	0.046
5.60	5.50	0.0	106.4	0.100	0.0	102.19	4.81	359.81	37.58	21.25	0.0	0.045
5.30	5.20	0.0	108.6	0.102	0.0	104.60	4.60	364.41	38.06	22.74	0.0	0.042
5.10	5.00	0.0	124.7	0.117	0.0	119.80	2.20	366.61	38.29	54.45	0.0	0.018
5.80	5.65	0.0	115.2	0.108	0.0	113.00	2.80	369.41	38.58	40.36	0.0	0.024

TABLE A19 (CONTINUED)

RESULTS OF RUN LC19
[0.20 HCPV CO2 @ 5.50 MPa (0.70 g-mol) 4:1 WAG, 10-Slugs]

Porosity [%] = 34.4
Oil Viscosity [mPa.s] = 1059.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 44.76

Pore Volume [cm3] = 1062.0
Initial Oil Saturation [%] = 89.2
Hydrocarbon Pore Volume [cm3] = 957.5
Carbon Dioxide Retention [%inj] = 98.90

Connate Water Saturation [%] = 10.8
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 12.3631
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
5.60	5.42	0.0	118.4	0.111	0.0	117.70	4.20	373.61	39.02	28.02	0.0	0.035
6.00	5.75	0.0	111.8	0.105	0.0	107.56	3.94	377.55	39.43	27.30	0.0	0.035
5.91	5.70	0.0	135.3	0.127	0.0	132.25	2.45	380.00	39.69	53.98	0.0	0.018
5.60	5.40	0.0	152.0	0.143	0.0	145.70	4.30	384.30	40.14	33.88	0.0	0.028
5.90	5.70	0.0	117.0	0.110	0.0	111.70	6.30	390.60	40.79	17.73	0.0	0.054
5.90	5.70	0.0	119.4	0.112	0.0	116.46	6.54	397.14	41.48	17.81	0.0	0.055
6.10	5.95	0.0	156.7	0.148	0.0	150.40	8.30	405.44	42.34	18.12	0.0	0.053
5.10	4.90	0.0	87.7	0.083	0.0	88.98	3.02	408.46	42.66	29.46	0.0	0.034
0.10	0.10	0.0	0.0	0.0	0.0	7.00	2.10	410.56	42.88	3.33	0.0	

TABLE A20

RESULTS OF RUN LC20
[0.20 HCPV CO2 @ 5.50 MPa (0.78 g-mol) 4:1 WAG, 10-Slugs]

Porosity [%] = 35.8
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 37.76

Pore Volume [cm3] = 1112.0
Initial Oil Saturation [%] = 89.3
Hydrocarbon Pore Volume [cm3] = 993.5
Carbon Dioxide Retention [%inj] = 80.04

Connate Water Saturation [%] = 10.7
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 12.4512
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
5.50	5.50	19.9	0.0	0.018	0.0	0.0	0.01	0.01	0.00	0.0	0.0	0.001
5.70	5.50	0.0	79.5	0.071	0.048	0.0	70.50	70.51	7.10	0.0	0.68	0.887
5.50	5.50	19.9	0.0	0.018	0.0	0.0	5.00	75.51	7.60	0.0	0.0	0.252
5.90	5.50	0.0	79.5	0.071	0.033	12.50	66.00	141.51	14.24	0.19	0.50	0.830
5.50	5.00	19.9	0.0	0.018	0.0	0.75	2.75	144.26	14.52	0.27	0.0	0.138
5.94	5.50	0.0	79.5	0.072	0.037	38.00	41.50	185.76	18.70	0.92	0.89	0.522
5.50	5.10	19.9	0.0	0.018	0.0	1.50	2.00	187.76	18.90	0.75	0.0	0.101
6.00	5.50	0.0	79.5	0.071	0.152	38.00	40.50	228.26	22.98	0.94	3.75	0.510
5.50	5.50	19.9	0.0	0.018	0.0	0.80	3.70	231.96	23.35	0.22	0.0	0.186
5.82	5.50	0.0	79.7	0.072	0.150	49.50	30.00	261.96	26.37	1.65	5.00	0.376
5.50	5.50	19.9	0.0	0.018	0.0	4.00	2.50	264.46	26.62	1.60	0.0	0.126
5.80	5.50	0.0	79.5	0.072	0.219	57.00	19.00	283.46	28.53	3.00	11.53	0.239
5.50	5.50	19.9	0.0	0.018	0.0	1.50	2.50	285.96	28.78	0.60	0.0	0.126
5.80	5.50	0.0	79.5	0.072	0.234	64.50	15.50	301.46	30.34	4.16	15.10	0.195
5.50	4.60	19.9	0.0	0.018	0.0	1.50	3.50	304.96	30.70	0.43	0.0	0.176
5.90	5.60	0.0	79.5	0.071	0.157	64.00	12.50	317.46	31.95	5.12	12.56	0.157
5.50	5.50	19.9	0.0	0.018	0.001	0.50	3.00	320.46	32.26	0.17	0.33	0.151

TABLE A20 (CONTINUED)

RESULTS OF RUN LC20
[0.20 HCPV CO2 @ 5.50 MPa (0.78 g-mol) 4:1 WAG, 10-Slugs]

Porosity [%] = 35.8
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 37.76

Pore Volume [cm3] = 1112.0
Initial Oil Saturation [%] = 89.3
Hydrocarbon Pore Volume [cm3] = 993.5
Carbon Dioxide Retention [%inj] = 80.04

Connate Water Saturation [%] = 10.7
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 12.4512
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
5.80	5.50	0.0	79.5	0.071	0.188	70.00	11.50	331.96	33.41	6.09	16.35	0.145
5.50	5.40	19.9	0.0	0.018	0.004	1.00	2.50	334.46	33.67	0.40	1.60	0.126
5.90	5.50	0.0	79.5	0.072	0.126	70.00	10.00	344.46	34.67	7.00	12.60	0.126
5.80	5.50	0.0	471.2	0.424	0.730	423.00	58.00	402.46	40.51	7.29	12.59	0.123
5.80	5.50	0.0	488.7	0.439	0.725	458.00	38.00	440.46	44.34	12.05	19.08	0.078
5.80	5.50	0.0	492.0	0.442	0.548	481.00	27.00	467.46	47.05	17.81	20.30	0.055
5.80	5.50	0.0	450.8	0.405	0.322	440.00	17.00	484.46	48.76	25.88	18.94	0.038
0.10	0.10	0.0	0.0	0.0	0.0	2.00	3.00	487.46	49.07	0.67	0.0	

TABLE A21

RESULTS OF RUN LC21
[0.10 HCPV CO2 @ 5.50 MPa (0.42 g-mol) 4:1 WAG, 10-Slugs]

Porosity [%] = 36.7
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 18.90

Pore Volume [cm3] = 1141.0
Initial Oil Saturation [%] = 93.9
Hydrocarbon Pore Volume [cm3] = 1072.0
Carbon Dioxide Retention [%inj] = 68.21

Connate Water Saturation [%] = 6.1
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 15.0946
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
5.50	5.50	10.7	0.0	0.009	0.0	0.0	0.01	0.01	0.00	0.0	0.0	0.001
6.00	5.50	0.0	42.9	0.038	0.002	0.0	3.50	3.51	0.33	0.0	0.57	0.082
5.50	5.50	10.7	0.0	0.009	0.0	0.0	5.50	9.01	0.84	0.0	0.0	0.513
5.90	5.50	0.0	42.9	0.038	0.023	0.0	41.50	50.51	4.71	0.0	0.55	0.967
5.50	5.50	10.7	0.0	0.009	0.002	0.0	10.50	61.01	5.69	0.0	0.19	0.979
5.80	5.50	0.0	42.9	0.038	0.047	0.50	39.50	100.51	9.38	0.01	1.19	0.921
5.50	5.50	10.7	0.0	0.009	0.169	1.00	9.00	109.51	10.22	0.11	18.78	0.840
5.74	5.54	0.0	42.9	0.038	0.540	11.75	26.25	135.76	12.66	0.45	20.57	0.612
5.50	5.50	10.7	0.0	0.009	0.112	3.50	7.75	143.51	13.39	0.45	14.45	0.723
5.70	5.52	0.0	42.9	0.038	0.469	14.50	23.50	167.01	15.58	0.62	19.96	0.548
5.50	5.50	10.7	0.0	0.009	0.155	6.00	7.00	174.01	16.23	0.86	22.14	0.653
5.70	5.50	0.0	42.8	0.038	0.588	10.50	26.00	200.01	18.66	0.40	22.62	0.608
5.50	5.20	10.7	0.0	0.009	0.320	15.50	15.50	215.51	20.10	1.00	20.65	1.446
5.80	5.50	0.0	42.9	0.038	0.307	11.50	10.00	225.51	21.04	1.15	30.70	0.233
5.50	5.00	10.7	0.0	0.009	1.328	21.00	17.00	242.51	22.62	1.24	78.12	1.586
5.50	5.20	0.0	42.9	0.038	1.351	6.00	9.50	252.01	23.51	0.63	142.21	0.221
5.50	5.20	10.7	0.0	0.009	0.561	14.50	8.50	260.51	24.30	1.71	66.00	0.793

TABLE A21 (CONTINUED)

RESULTS OF RUN LC21
[0.10 HCPV CO2 @ 5.50 MPa (0.42 g-mol) 4:1 WAG, 10-Slugs]

Porosity [%] = 36.7	Pore Volume [cm3] = 1141.0	Connate Water Saturation [%] = 6.1
Oil Viscosity [mPa.s] = 1055.3	Initial Oil Saturation [%] = 93.9	Molar Density @ atm. [kmol/m3] = 0.04166
Average Run Temperature [K] = 294.15	Hydrocarbon Pore Volume [cm3] = 1072.0	Absolute Permeability [darcies] = 15.0946
Carbon Dioxide Required [sm3/sm3] = 18.90	Carbon Dioxide Retention [%inj] = 68.21	Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
5.50	5.40	0.0	42.9	0.038	1.359	16.00	12.50	273.01	25.47	1.28	108.72	0.292
5.50	5.50	10.7	0.0	0.009	0.479	16.50	6.50	279.51	26.07	2.54	73.69	0.606
5.55	5.40	0.0	42.9	0.038	1.721	18.00	11.50	291.01	27.15	1.57	149.65	0.268
5.50	5.50	0.0	472.4	0.414	5.023	365.00	94.00	385.01	35.92	3.88	53.44	0.199
5.64	5.54	0.0	497.6	0.436	1.666	463.00	34.00	419.01	39.09	13.62	49.00	0.068
5.55	5.50	0.0	488.9	0.428	0.677	473.00	27.00	446.01	41.61	17.52	25.07	0.055
5.59	5.50	0.0	494.7	0.434	0.237	485.00	25.00	471.01	43.94	19.40	9.48	0.051
4.87	4.40	0.0	153.3	0.134	0.175	150.00	12.00	483.01	45.06	12.50	14.58	0.078
0.10	0.10	0.0	0.0	0.0	0.330	223.00	34.50	517.51	48.28	6.46	9.57	
0.10	0.10	0.0	0.0	0.0	0.151	53.50	8.00	525.51	49.02	6.69	18.88	

TABLE A22

RESULTS OF RUN LC22
[0.20 HCPV CO2 @ 1.00MPa (0.09 g-mol) 4:1 WAG, 10-Slugs, Wainwright]

Porosity [%] = 36.7
Oil Viscosity [mPa.s] = 150.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 3.43

Pore Volume [cm3] = 1140.0
Initial Oil Saturation [%] = 88.2
Hydrocarbon Pore Volume [cm3] = 1005.5
Carbon Dioxide Retention [%inj] = 6.07

Connate Water Saturation [%] = 11.8
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 11.4142
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.02	0.90	29.5	0.0	0.026	0.0	0.0	5.30	5.30	0.53	0.0	0.0	0.180
1.00	1.00	0.0	80.5	0.071	0.0	0.0	46.80	52.10	5.18	0.0	0.0	0.582
1.03	0.97	20.1	0.0	0.018	0.026	0.0	23.50	75.60	7.52	0.0	1.11	1.169
1.00	1.00	0.0	81.6	0.072	0.021	0.0	53.30	128.90	12.82	0.0	0.39	0.653
1.02	1.00	20.1	0.0	0.018	0.003	0.0	18.00	146.90	14.61	0.0	0.17	0.895
1.00	1.00	0.0	81.4	0.071	0.025	0.0	63.50	210.40	20.93	0.0	0.39	0.780
1.04	1.00	20.1	0.0	0.018	0.005	0.20	18.20	228.60	22.74	0.01	0.27	0.905
1.00	1.00	0.0	80.4	0.071	0.022	8.90	56.40	285.00	28.34	0.16	0.39	0.701
1.04	0.98	20.1	0.0	0.018	0.003	5.90	12.80	297.80	29.62	0.46	0.23	0.636
1.00	1.00	0.0	80.4	0.070	0.015	25.10	40.90	338.70	33.69	0.61	0.37	0.509
1.01	1.00	20.1	0.0	0.018	0.003	9.20	10.25	348.95	34.70	0.90	0.29	0.510
1.00	1.00	0.0	80.0	0.070	0.027	37.90	27.80	376.75	37.47	1.36	0.97	0.348
1.01	1.00	20.1	0.0	0.018	0.012	13.00	8.20	384.95	38.29	1.59	1.46	0.408
1.00	1.00	0.0	80.7	0.071	0.038	42.40	23.60	408.55	40.63	1.80	1.61	0.292
1.03	1.00	20.9	0.0	0.018	0.001	13.87	6.93	415.48	41.32	2.00	0.14	0.332
1.00	1.00	0.0	80.4	0.071	0.019	46.70	19.20	434.68	43.23	2.43	0.99	0.239
1.00	0.98	19.2	0.0	0.017	0.010	10.88	11.12	445.80	44.34	0.98	0.90	0.579

TABLE A22 (CONTINUED)

RESULTS OF RUN LC22
[0.20 HCPV CO2 @ 1.00MPa (0.09 g-mol) 4:1 WAG, 10-Slugs, Wainwright]

Porosity [%] = 36.7
Oil Viscosity [mPa.s] = 150.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 3.43

Pore Volume [cm3] = 1140.0
Initial Oil Saturation [%] = 88.2
Hydrocarbon Pore Volume [cm3] = 1005.5
Carbon Dioxide Retention [%inj] = 6.07

Connate Water Saturation [%] = 11.8
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 11.4142
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.00	1.00	0.0	80.5	0.071	0.037	45.65	15.65	461.45	45.89	2.92	2.36	0.194
1.01	1.00	20.1	0.0	0.018	0.014	13.91	4.05	465.50	46.30	3.43	3.46	0.201
1.00	1.00	0.0	80.8	0.071	0.065	57.00	15.30	480.80	47.82	3.73	4.25	0.189
1.00	1.00	0.0	130.2	0.114	0.104	95.00	24.70	505.50	50.27	3.85	4.21	0.190
1.00	1.00	0.0	162.9	0.143	0.116	139.30	22.90	528.40	52.55	6.08	5.07	0.141
1.00	1.00	0.0	135.0	0.118	0.093	118.20	16.80	545.20	54.22	7.04	5.54	0.124
1.00	1.00	0.0	142.2	0.125	0.101	127.10	15.00	560.20	55.71	8.47	6.73	0.106
1.00	1.00	0.0	190.3	0.167	0.157	178.00	16.90	577.10	57.40	10.53	9.29	0.089
1.00	1.00	0.0	153.6	0.135	0.161	141.70	13.10	590.20	58.70	10.82	12.29	0.085
1.00	1.00	0.0	126.8	0.111	0.128	117.90	10.10	600.30	59.70	11.67	12.67	0.080
1.00	1.00	0.0	99.1	0.087	0.106	96.00	6.85	607.15	60.38	14.01	15.47	0.069
1.00	1.00	0.0	145.4	0.128	0.187	137.00	9.10	616.25	61.29	15.05	20.55	0.063
1.00	1.00	0.0	154.5	0.135	0.119	147.10	8.90	625.15	62.17	16.53	13.37	0.058
1.00	1.00	0.0	199.6	0.175	0.118	196.00	7.70	632.85	62.94	25.45	15.32	0.039
1.00	1.00	0.0	84.6	0.074	0.059	84.00	4.10	636.95	63.35	20.49	14.39	0.048
0.10	0.10	0.0	0.0	0.0	0.307	120.30	16.20	653.15	64.96	7.43	18.95	

TABLE A23

RESULTS OF RUN LC23(a,b)
[2.29 HCPV WF=> 0.20 RHCPV CO2 @ 1.00 MPa (0.05 g-mol) 4:1 WAG, Wainwright]

Porosity [%] = 36.2
Oil Viscosity [mPa.s] = 150.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 1.17

Pore Volume [cm3] = 1127.0
Initial Oil Saturation [%] = 87.1
Hydrocarbon Pore Volume [cm3] = 981.1
Carbon Dioxide Retention [%inj] = 12.52

Connate Water Saturation [%] = 12.9
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 11.4569
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.14	1.02	0.0	82.6	0.073	0.0	0.0	67.00	67.00	6.83	0.0	0.0	0.811
1.11	1.01	0.0	73.1	0.065	0.0	0.0	74.80	141.80	14.45	0.0	0.0	1.023
1.12	1.04	0.0	62.1	0.055	0.0	0.0	64.00	205.80	20.98	0.0	0.0	1.030
1.10	1.01	0.0	71.9	0.064	0.0	2.90	69.60	275.40	28.07	0.04	0.0	0.968
1.11	1.03	0.0	71.1	0.063	0.0	21.00	51.90	327.30	33.36	0.40	0.0	0.730
1.15	1.09	0.0	159.5	0.142	0.0	86.70	75.50	402.80	41.06	1.15	0.0	0.473
1.00	1.00	0.0	170.7	0.151	0.0	127.60	45.50	448.30	45.70	2.80	0.0	0.267
1.00	1.00	0.0	138.8	0.123	0.0	117.90	27.90	476.20	48.54	4.23	0.0	0.201
1.00	1.00	0.0	162.9	0.145	0.0	138.00	23.90	500.10	50.98	5.77	0.0	0.147
1.00	1.00	0.0	231.5	0.205	0.0	211.68	23.72	523.82	53.39	8.92	0.0	0.102
1.00	1.00	0.0	180.3	0.160	0.0	167.30	16.36	540.18	55.06	10.23	0.0	0.091
1.00	1.00	0.0	164.3	0.146	0.0	154.00	12.10	552.28	56.29	12.73	0.0	0.074
1.00	1.00	0.0	104.2	0.092	0.0	98.31	8.44	560.72	57.15	11.65	0.0	0.081
1.00	1.00	0.0	170.1	0.151	0.0	160.00	11.90	572.62	58.37	13.45	0.0	0.070
1.00	1.00	0.0	192.6	0.171	0.0	189.88	10.03	582.65	59.39	18.93	0.0	0.052
1.00	1.00	0.0	114.3	0.101	0.0	105.00	6.77	589.42	60.08	15.51	0.0	0.059
1.00	1.00	0.0	92.3	0.082	0.0	88.82	6.18	595.60	60.71	14.37	0.0	0.067

TABLE A23 (CONTINUED)

RESULTS OF RUN LC23(a,b)
[2.29 HCPV WF=> 0.20 RHCPV CO2 @ 1.00 MPa (0.05 g-mol) 4:1 WAG, Wainwright]

Porosity [%] = 36.2
Oil Viscosity [mPa.s] = 150.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 1.17

Pore Volume [cm3] = 1127.0
Initial Oil Saturation [%] = 87.1
Hydrocarbon Pore Volume [cm3] = 981.1
Carbon Dioxide Retention [%inj] = 12.52

Connate Water Saturation [%] = 12.9
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 11.4569
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.06	1.00	8.6	0.0	0.008	0.0	4.90	0.40	596.00	60.75	12.25	0.0	0.047
1.00	1.00	0.0	30.8	0.027	0.0	21.70	10.80	606.80	61.85	2.01	0.0	0.351
1.01	1.00	8.6	0.0	0.008	0.0	10.40	1.60	608.40	62.01	6.50	0.0	0.187
1.00	1.00	0.0	30.9	0.027	0.045	23.20	2.80	611.20	62.30	8.29	16.07	0.091
1.13	1.04	8.6	0.0	0.008	0.006	11.10	1.75	612.95	62.48	6.34	3.43	0.205
1.00	1.00	0.0	30.8	0.027	0.010	18.00	1.00	613.95	62.58	18.00	10.00	0.032
1.11	0.97	8.6	0.0	0.008	0.011	16.67	1.22	615.17	62.71	13.66	9.02	0.143
1.00	1.00	0.0	30.8	0.027	0.018	19.00	1.60	616.77	62.87	11.87	11.25	0.052
1.04	0.98	8.6	0.0	0.008	0.012	19.97	1.03	617.80	62.97	19.39	11.65	0.120
1.00	1.00	0.0	30.9	0.027	0.020	24.63	2.57	620.37	63.24	9.58	7.78	0.083
1.11	0.97	8.6	0.0	0.008	0.020	12.00	1.66	622.03	63.40	7.23	12.05	0.194
1.00	1.00	0.0	30.9	0.027	0.006	16.28	0.71	622.74	63.48	22.93	8.45	0.023
1.00	0.91	8.6	0.0	0.008	0.002	5.58	0.63	623.37	63.54	8.86	3.17	0.074
1.00	1.00	0.0	31.5	0.028	0.011	25.00	0.82	624.19	63.62	30.49	13.41	0.026
0.99	0.86	8.6	0.0	0.008	0.008	11.96	0.47	624.66	63.67	25.45	17.02	0.055
1.00	1.00	0.0	86.3	0.077	0.051	75.57	1.32	625.98	63.81	57.25	38.64	0.015
0.10	0.10	0.0	0.0	0.0	0.440	168.11	18.09	644.07	65.65	9.29	24.32	

TABLE A24

RESULTS OF RUN TD 1

[0.61 HCPV CO2 @ 2.50 MPa (1.41 g-mol) 4:1 WAG, 10-Slugs, SENLAC]

Porosity [%] = 43.1
Oil Viscosity [mPa.s] = 3295.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 45.38

Pore Volume [cm3] = 2100.3
Initial Oil Saturation [%] = 86.8
Hydrocarbon Pore Volume [cm3] = 1822.2
Carbon Dioxide Retention [%inj] = 48.91

Connate Water Saturation [%] = 13.2
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 7.6168
Average Flow Velocity [m/d] = 0.776

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
2.70	2.50	106.4	79.5	0.089	0.0	0.0	60.70	60.70	3.33	0.0	0.0	0.327
3.72	2.46	0.0	125.9	0.060	0.0	0.0	123.10	183.80	10.09	0.0	0.0	0.978
3.45	2.42	0.0	160.4	0.076	0.0	57.70	106.30	290.10	15.92	0.54	0.0	0.663
3.01	2.41	0.0	103.4	0.049	0.0	68.60	28.60	318.70	17.49	2.40	0.0	0.277
2.71	2.35	106.1	0.0	0.051	0.0	50.80	24.50	343.20	18.83	2.07	0.0	0.231
2.76	2.29	0.0	266.4	0.127	0.0	149.70	50.10	393.30	21.58	2.99	0.0	0.188
2.66	2.50	0.0	236.8	0.113	0.0	173.30	36.90	430.20	23.61	4.70	0.0	0.156
2.67	2.50	108.3	0.0	0.052	0.0	59.70	9.20	439.40	24.11	6.49	0.0	0.085
2.61	2.50	0.0	150.3	0.072	0.0	102.40	15.90	455.30	24.99	6.44	0.0	0.106
2.70	2.62	0.0	172.2	0.082	0.0	170.30	16.60	471.90	25.90	10.26	0.0	0.096
2.60	2.50	0.0	143.8	0.068	0.0	95.50	12.20	484.10	26.57	7.83	0.0	0.085
2.58	2.48	112.1	0.0	0.053	0.0	89.90	10.70	494.80	27.15	8.40	0.0	0.095
2.61	2.53	0.0	231.5	0.110	0.0	142.20	14.10	508.90	27.93	10.09	0.0	0.061
2.70	2.55	0.0	234.6	0.112	0.0	187.00	20.70	529.60	29.06	9.03	0.0	0.088
2.59	2.51	111.5	0.0	0.053	0.005	74.20	8.50	538.10	29.53	8.73	0.59	0.076
2.50	2.50	0.0	269.1	0.128	0.225	186.30	15.70	553.80	30.39	11.87	14.33	0.058
2.60	2.53	0.0	198.1	0.094	0.239	179.40	18.70	572.50	31.42	9.59	12.78	0.094

TABLE A24 (CONTINUED)

RESULTS OF RUN TD 1

[0.61 HCPV CO2 @ 2.50 MPa (1.41 g-mol) 4:1 WAG, 10-Slugs, SENLAC]

Porosity [%] = 43.1
Oil Viscosity [mPa.s] = 3295.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 45.38

Pore Volume [cm3] = 2100.3
Initial Oil Saturation [%] = 86.8
Hydrocarbon Pore Volume [cm3] = 1822.2
Carbon Dioxide Retention [%inj] = 48.91

Connate Water Saturation [%] = 13.2
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 7.6168
Average Flow Velocity [m/d] = 0.776

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
2.58	2.51	112.8	0.0	0.054	0.055	56.80	7.40	579.90	31.82	7.68	7.43	0.066
2.59	2.47	0.0	241.0	0.115	0.665	176.10	17.90	597.80	32.81	9.84	37.15	0.074
2.49	2.47	0.0	226.2	0.108	0.721	204.00	17.80	615.60	33.78	11.46	40.51	0.079
2.60	2.54	111.4	0.0	0.053	0.316	82.00	7.30	622.90	34.18	11.23	43.29	0.066
2.69	2.63	0.0	270.8	0.129	1.144	175.90	14.30	637.20	34.97	12.30	80.00	0.053
2.54	2.50	0.0	183.3	0.087	1.089	167.60	13.10	650.30	35.69	12.79	83.13	0.071
2.51	2.47	116.2	0.0	0.055	0.468	68.04	4.00	654.30	35.91	17.01	117.00	0.034
2.59	2.53	0.0	248.4	0.118	0.902	185.80	10.50	664.80	36.48	17.70	85.90	0.042
2.82	2.71	0.0	218.8	0.104	1.281	196.00	11.70	676.50	37.13	16.75	109.49	0.053
2.58	2.51	112.4	0.0	0.054	0.162	59.00	2.80	679.30	37.28	21.07	57.86	0.025
2.48	2.40	0.0	238.7	0.114	1.118	192.00	8.20	687.50	37.73	23.41	136.34	0.034
2.44	2.39	0.0	245.8	0.117	0.413	213.80	10.40	697.90	38.30	20.56	39.71	0.042
2.50	2.47	117.6	0.0	0.056	0.467	79.70	4.10	702.00	38.52	19.44	113.90	0.035
2.50	2.50	0.0	238.9	0.114	0.750	149.00	6.30	708.30	38.87	23.65	119.05	0.026
2.59	2.55	0.0	231.4	0.110	0.678	222.00	9.40	717.70	39.39	23.62	72.13	0.041
0.10	0.10	0.0	0.0	0.0	6.566	299.80	26.90	744.60	40.86	11.14	244.09	

TABLE A25

RESULTS OF RUN TD 2
[0.33 HCPV CO2 @ 4.10 MPa (1.41 g-mol) 4:1 WAG, 10-Slugs, SENLAC]

Porosity [%] = 41.5
Oil Viscosity [mPa.s] = 3295.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 40.15

Pore Volume [cm3] = 2022.5
Initial Oil Saturation [%] = 90.1
Hydrocarbon Pore Volume [cm3] = 1822.5
Carbon Dioxide Retention [%inj] = 28.68

Connate Water Saturation [%] = 9.9
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 7.4048
Average Flow Velocity [m/d] = 0.776

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
4.10	3.94	61.2	0.0	0.030	0.0	0.0	7.79	7.79	0.43	0.0	0.0	0.127
4.94	4.19	0.0	244.7	0.121	0.096	34.40	196.60	204.39	11.21	0.17	0.49	0.803
4.10	4.02	61.2	0.0	0.030	0.469	16.90	14.90	219.29	12.03	1.13	31.48	0.244
4.49	4.21	0.0	159.5	0.079	0.868	58.90	80.80	300.09	16.47	0.73	10.74	0.507
4.29	4.10	0.0	85.2	0.042	0.519	46.70	37.90	337.99	18.55	1.23	13.69	0.445
4.10	3.91	61.2	0.0	0.030	0.181	23.80	14.20	352.19	19.32	1.68	12.75	0.232
4.21	4.10	0.0	144.6	0.071	0.773	84.10	43.30	395.99	21.73	1.92	17.65	0.303
4.17	4.10	0.0	100.1	0.050	0.633	76.00	23.80	419.79	23.03	3.19	26.60	0.238
4.10	4.00	61.2	0.0	0.030	0.119	32.90	8.30	428.09	23.49	3.96	14.34	0.136
4.22	4.10	0.0	125.5	0.062	0.363	81.80	19.50	447.59	24.56	4.19	18.62	0.155
4.17	4.10	0.0	119.3	0.059	0.408	90.10	24.40	471.99	25.90	3.69	16.72	0.205
4.10	4.00	61.2	0.0	0.030	0.214	29.20	11.90	483.89	26.55	2.45	17.98	0.194
4.09	4.04	0.0	131.7	0.065	0.487	77.70	24.30	508.19	27.88	3.20	20.04	0.185
4.10	4.09	0.0	113.0	0.056	0.376	85.50	24.80	532.99	29.25	3.45	15.16	0.219
4.10	4.04	61.2	0.0	0.030	0.060	26.90	7.90	540.89	29.68	3.41	7.59	0.129
4.23	4.00	0.0	133.4	0.066	0.546	92.10	21.20	562.09	30.84	4.34	25.75	0.159
4.22	4.08	0.0	111.4	0.055	0.632	89.70	18.30	580.39	31.85	4.90	34.54	0.164

TABLE A25 (CONTINUED)

RESULTS OF RUN TD 2
[0.33 HCPV CO2 @ 4.10 MPa (1.41 g-mol) 4:1 WAG, 10-Slugs, SENLAC]

Porosity [%] = 41.5
Oil Viscosity [mPa.s] = 3295.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 40.15

Pore Volume [cm3] = 2022.5
Initial Oil Saturation [%] = 90.1
Hydrocarbon Pore Volume [cm3] = 1822.5
Carbon Dioxide Retention [%inj] = 28.68

Connate Water Saturation [%] = 9.9
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 7.4048
Average Flow Velocity [m/d] = 0.776

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
4.10	4.00	61.2	0.0	0.030	0.207	34.60	7.90	588.29	32.28	4.38	26.20	0.129
4.19	4.14	0.0	136.6	0.068	0.491	90.20	19.80	608.09	33.37	4.56	24.80	0.145
4.17	4.11	0.0	108.1	0.053	0.728	87.80	15.20	623.29	34.20	5.78	47.89	0.141
4.10	3.97	61.2	0.0	0.030	0.249	33.90	7.20	630.49	34.60	4.71	34.58	0.118
4.22	4.19	0.0	85.5	0.042	0.426	55.80	10.40	640.89	35.17	5.37	40.96	0.122
4.09	4.04	0.0	159.2	0.079	0.886	133.60	14.10	654.99	35.94	9.48	62.84	0.089
4.10	4.00	61.2	0.0	0.030	0.329	38.30	6.70	661.69	36.31	5.72	49.10	0.109
4.10	4.07	0.0	130.0	0.064	0.769	89.80	15.90	677.59	37.18	5.65	48.36	0.122
4.11	4.09	0.0	114.7	0.057	1.167	101.10	12.20	689.79	37.85	8.29	95.66	0.106
4.10	4.00	61.2	0.0	0.030	0.429	49.00	5.70	695.49	38.16	8.60	75.26	0.093
4.14	4.10	0.0	121.9	0.060	1.094	90.20	13.70	709.19	38.91	6.58	79.85	0.112
4.17	4.13	0.0	156.4	0.077	1.421	116.00	13.00	722.19	39.63	8.92	109.31	0.083
4.10	4.10	0.0	449.9	0.222	2.481	416.60	38.40	760.59	41.73	10.85	64.61	0.085
4.10	4.10	0.0	278.7	0.138	1.598	248.40	18.80	779.39	42.77	13.21	85.00	0.067
4.10	4.10	0.0	216.1	0.107	1.361	208.80	11.00	790.39	43.37	18.98	123.73	0.051
4.10	4.10	0.0	481.6	0.238	1.550	475.00	22.20	812.59	44.59	21.40	69.82	0.046
0.10	0.10	0.0	0.0	0.0	2.215	296.90	30.51	843.10	46.26	9.73	72.60	

TABLE A26

RESULTS OF RUN TD 3
[0.20 HCPV CO2 @ 1.00 MPa (0.16 g-mol) 4:1 WAG, 10-Slugs]

Porosity [%] = 40.6
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.83

Pore Volume [cm3] = 1977.0
Initial Oil Saturation [%] = 91.3
Hydrocarbon Pore Volume [cm3] = 1805.6
Carbon Dioxide Retention [%inj] = 65.99

Connate Water Saturation [%] = 8.7
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 13.3119
Average Flow Velocity [m/d] = 0.831

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.00	0.99	36.1	0.0	0.018	0.0	0.0	0.18	0.18	0.01	0.0	0.0	0.005
1.13	1.00	0.0	144.5	0.073	0.029	0.0	130.00	130.18	7.21	0.0	0.22	0.900
1.00	1.00	36.1	0.0	0.018	0.0	0.0	20.00	150.18	8.32	0.0	0.0	0.554
1.14	1.00	0.0	144.5	0.073	0.012	30.00	107.90	258.08	14.29	0.28	0.11	0.747
1.00	0.97	36.1	0.0	0.018	0.0	7.00	12.45	270.53	14.98	0.56	0.0	0.345
1.12	1.08	0.0	144.4	0.073	0.016	67.10	66.90	337.43	18.69	1.00	0.24	0.463
1.00	1.00	36.1	0.0	0.018	0.0	6.00	5.85	343.28	19.01	1.03	0.0	0.162
1.17	1.10	0.0	144.5	0.073	0.005	89.88	44.12	387.40	21.46	2.04	0.11	0.305
1.00	0.97	36.1	0.0	0.018	0.0	11.66	5.55	392.95	21.76	2.10	0.0	0.154
1.08	1.01	0.0	144.4	0.073	0.002	95.75	36.25	429.20	23.77	2.64	0.06	0.251
1.04	1.00	36.1	0.0	0.018	0.0	9.69	10.51	439.71	24.35	0.92	0.0	0.291
1.00	1.00	0.0	144.7	0.073	0.006	105.87	29.43	469.14	25.98	3.60	0.20	0.203
1.00	0.99	36.1	0.0	0.018	0.0	20.00	6.86	476.00	26.36	2.92	0.0	0.190
1.07	1.00	0.0	144.5	0.073	0.064	97.69	21.01	497.01	27.53	4.65	3.05	0.145
1.00	0.97	36.1	0.0	0.018	0.007	22.92	12.29	509.30	28.21	1.86	0.57	0.340
1.14	1.09	0.0	144.2	0.073	0.028	96.00	17.88	527.18	29.20	5.37	1.57	0.124
1.00	0.95	36.1	0.0	0.018	0.003	24.10	5.56	532.74	29.50	4.33	0.54	0.154

TABLE A26 (CONTINUED)

RESULTS OF RUN TD 3
[0.20 HCPV CO2 @ 1.00 MPa (0.16 g-mol) 4:1 WAG, 10-Slugs]

Porosity [%] = 40.6
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.83

Pore Volume [cm3] = 1977.0
Initial Oil Saturation [%] = 91.3
Hydrocarbon Pore Volume [cm3] = 1805.6
Carbon Dioxide Retention [%inj] = 65.99

Connate Water Saturation [%] = 8.7
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 13.3119
Average Flow Velocity [m/d] = 0.831

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.04	0.0	144.4	0.073	0.0	109.63	16.78	549.52	30.43	6.53	0.0	0.116
1.00	1.00	36.1	0.0	0.018	0.0	20.49	4.51	554.03	30.68	4.54	0.0	0.125
1.07	1.00	0.0	146.0	0.074	0.076	109.20	14.80	568.83	31.50	7.38	5.14	0.101
1.00	1.00	0.0	161.3	0.082	0.0	145.13	18.76	587.59	32.54	7.74	0.0	0.116
1.00	1.00	0.0	175.9	0.089	0.0	160.00	18.82	606.41	33.58	8.50	0.0	0.107
1.00	1.00	0.0	168.1	0.085	0.0	154.63	15.37	621.78	34.44	10.06	0.0	0.091
1.00	1.00	0.0	100.8	0.051	0.0	91.66	10.34	632.12	35.01	8.86	0.0	0.103
1.00	1.00	0.0	146.0	0.074	0.003	130.00	13.10	645.22	35.73	9.92	0.23	0.090
1.00	1.00	0.0	168.6	0.085	0.050	157.10	14.30	659.52	36.53	10.99	3.50	0.085
1.00	1.00	0.0	176.1	0.089	0.081	164.10	13.90	673.42	37.30	11.81	5.83	0.079
1.00	1.00	0.0	124.9	0.063	0.074	116.00	9.90	683.32	37.84	11.72	7.47	0.079
1.00	1.00	0.0	365.7	0.185	0.226	342.20	25.11	708.43	39.23	13.63	9.00	0.069
1.00	1.00	0.0	181.6	0.092	0.055	172.20	10.70	719.13	39.83	16.09	5.14	0.059
1.00	1.00	0.0	195.4	0.099	0.060	184.00	10.80	729.93	40.43	17.04	5.56	0.055
1.00	1.00	0.0	120.0	0.061	0.041	115.40	6.24	736.17	40.77	18.49	6.57	0.052
1.00	1.00	0.0	161.8	0.082	0.053	153.71	8.09	744.26	41.22	19.00	6.55	0.050
1.00	1.00	0.0	133.1	0.067	0.057	126.66	6.41	750.67	41.57	19.76	8.89	0.048

TABLE A26 (CONTINUED)

RESULTS OF RUN TD 3
[0.20 HCPV CO2 @ 1.00 MPa (0.16 g-mol) 4:1 WAG, 10-Slugs]

Porosity [%] = 40.6
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.83

Pore Volume [cm3] = 1977.0
Initial Oil Saturation [%] = 91.3
Hydrocarbon Pore Volume [cm3] = 1805.6
Carbon Dioxide Retention [%inj] = 65.99

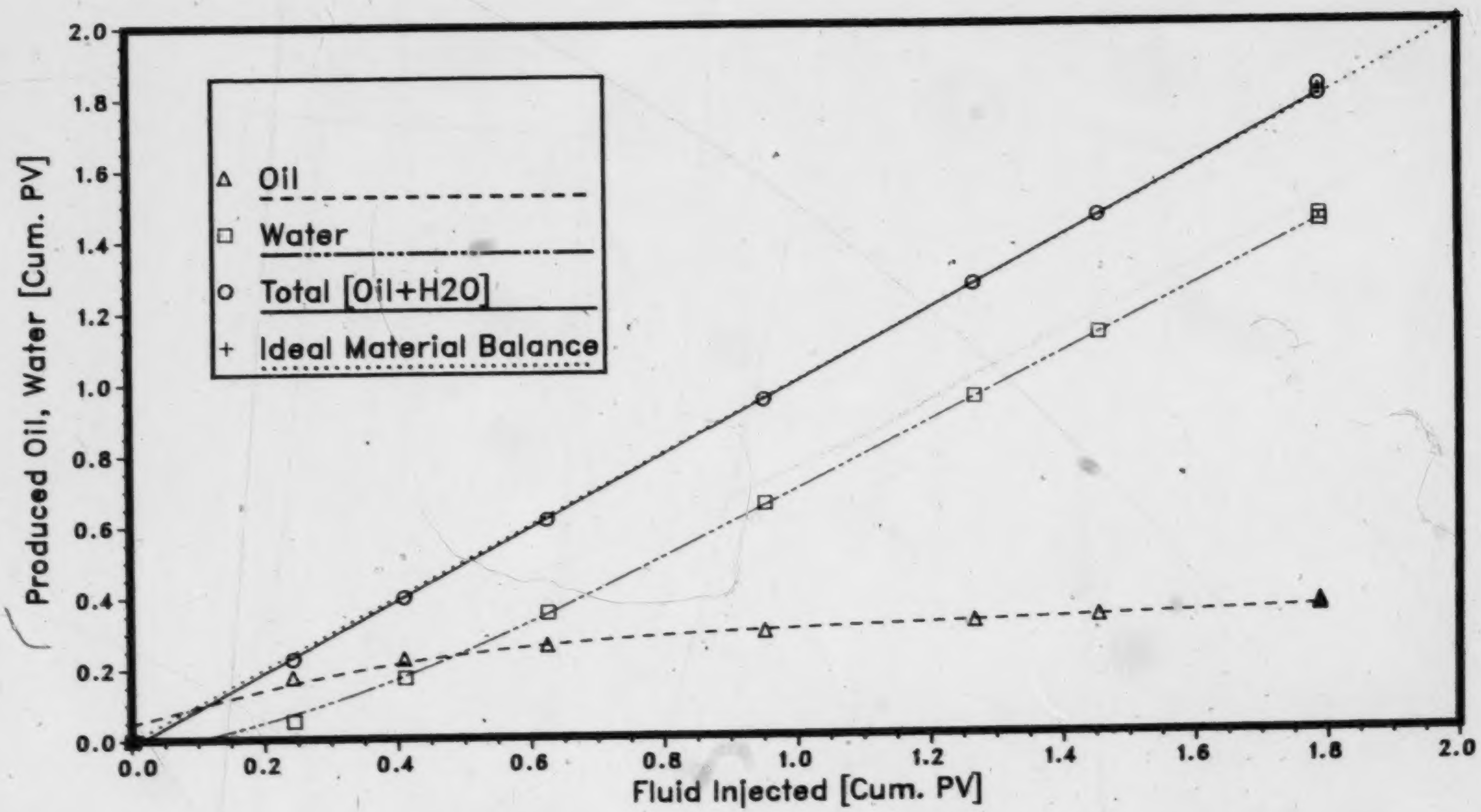
Connate Water Saturation [%] = 8.7
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 13.3119
Average Flow Velocity [m/d] = 0.831

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
0.10	0.10	0.0	0.0	0.0	0.335	85.00	31.10	781.77	43.30	2.73	10.77	

Appendix B

Volumetric Balance Plots of All Runs

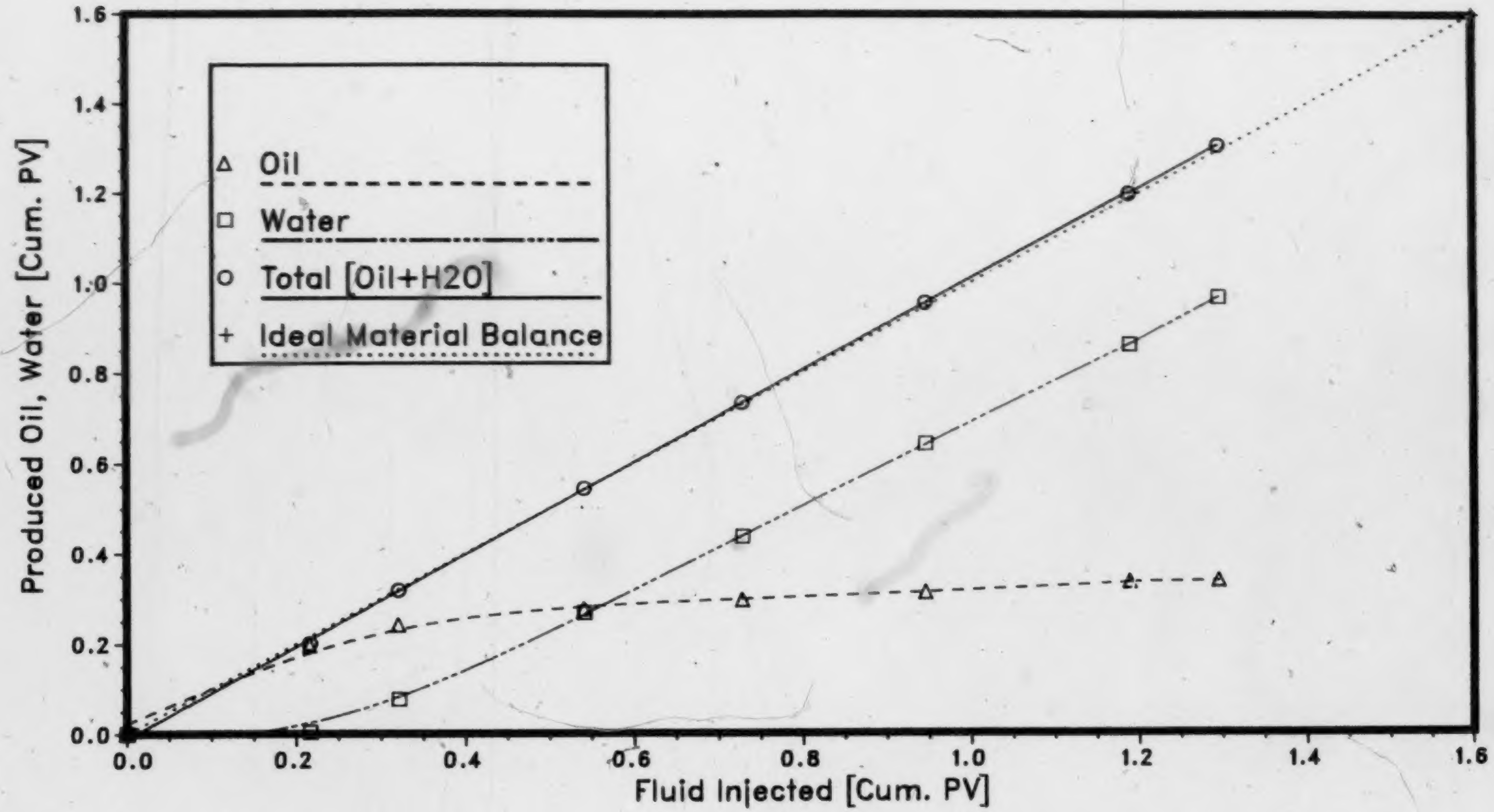
The following plots provide an indication of the individual volumes of oil, water, and gas produced, and the total. The total volumes are compared with the ideal total for a perfect volume balance. In this way, an idea can be formed of the material balance error.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1059.0 mPa.s
ϕ = 35.00 %, k = 11.100 darcies, S_o = 93.00 %, S_{wc} = 7.00 %

[1.92 HCPV Waterflood @ 1.00 MPa]

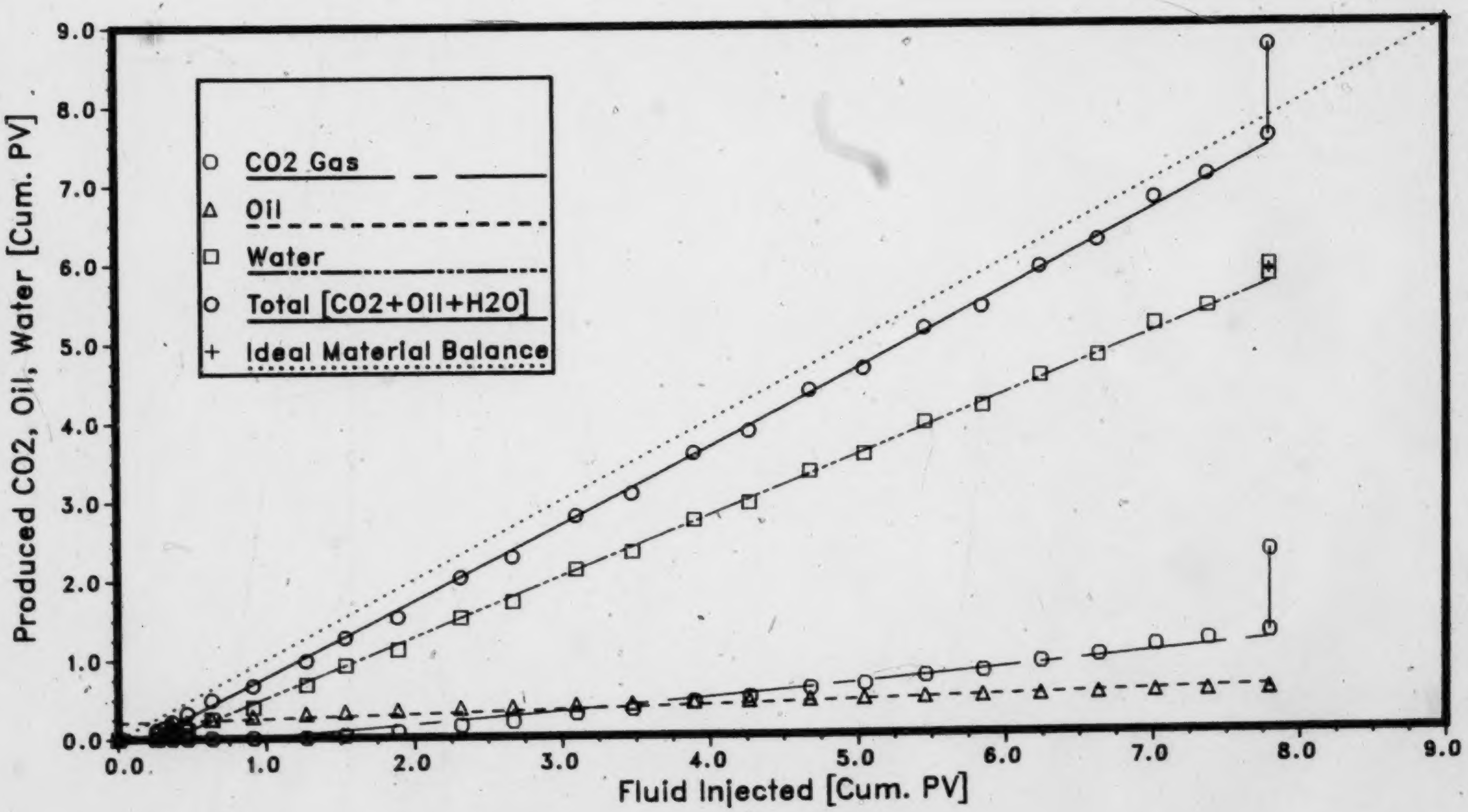
Figure B.1 Volumetric Balance on Run LC 1.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.256 m/d, μ_o = 1059.0 mPa.s
ϕ = 35.00 %, k = 5.580 darcies, S_o = 90.00 %, S_{wc} = 10.00 %

[1.44 HCPV Waterflood @ 1.00 MPa]

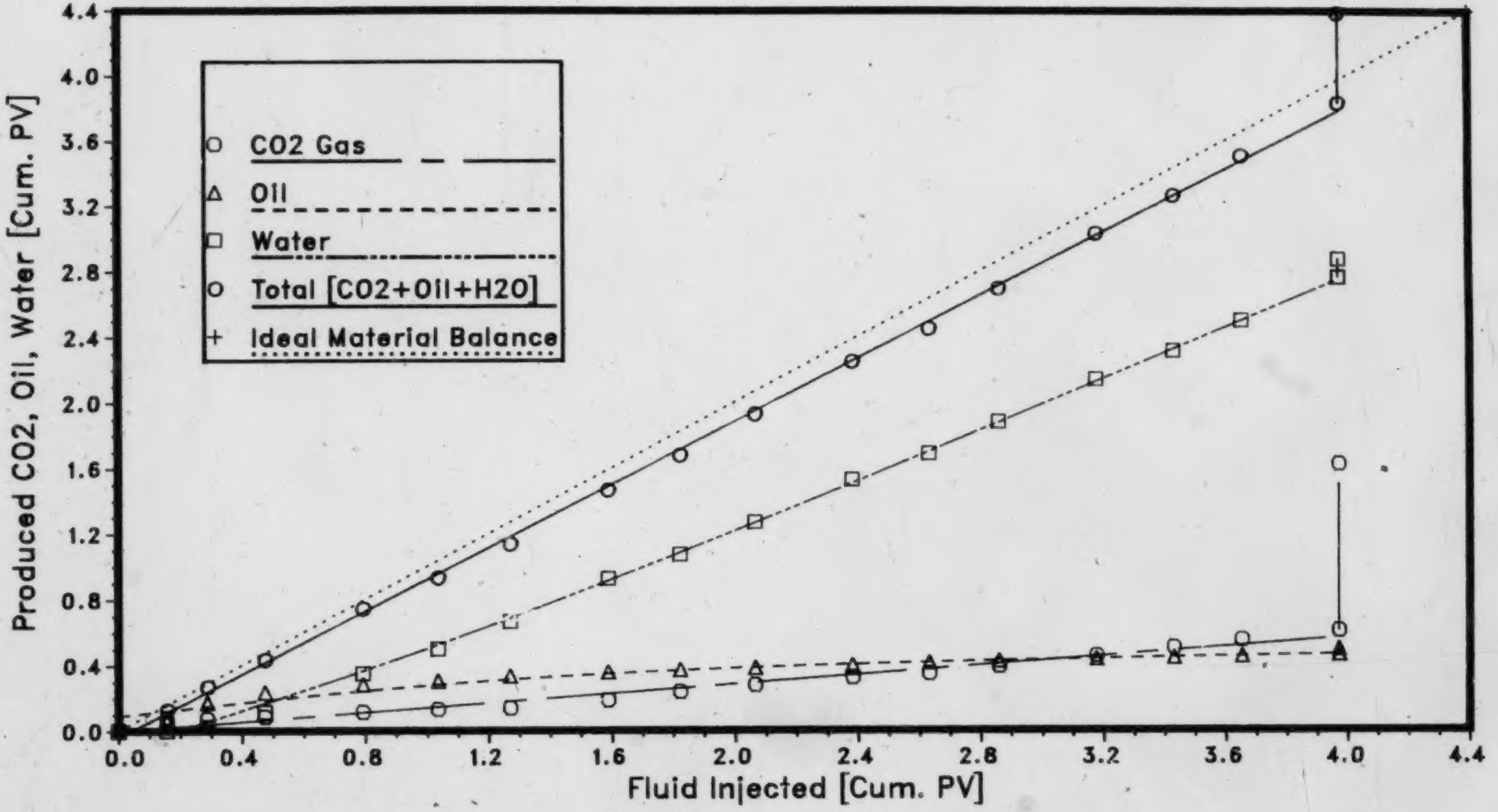
Figure B.2 Volumetric Balance on Run LC 2.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 36.60 %, k = 10.657 darcies, S_o = 87.32 %, S_{wc} = 12.70 %

[1.79 HCPV CO2 @ 1.00 MPa (0.77 g-mol) 4:1 WAG, 10-Slugs]

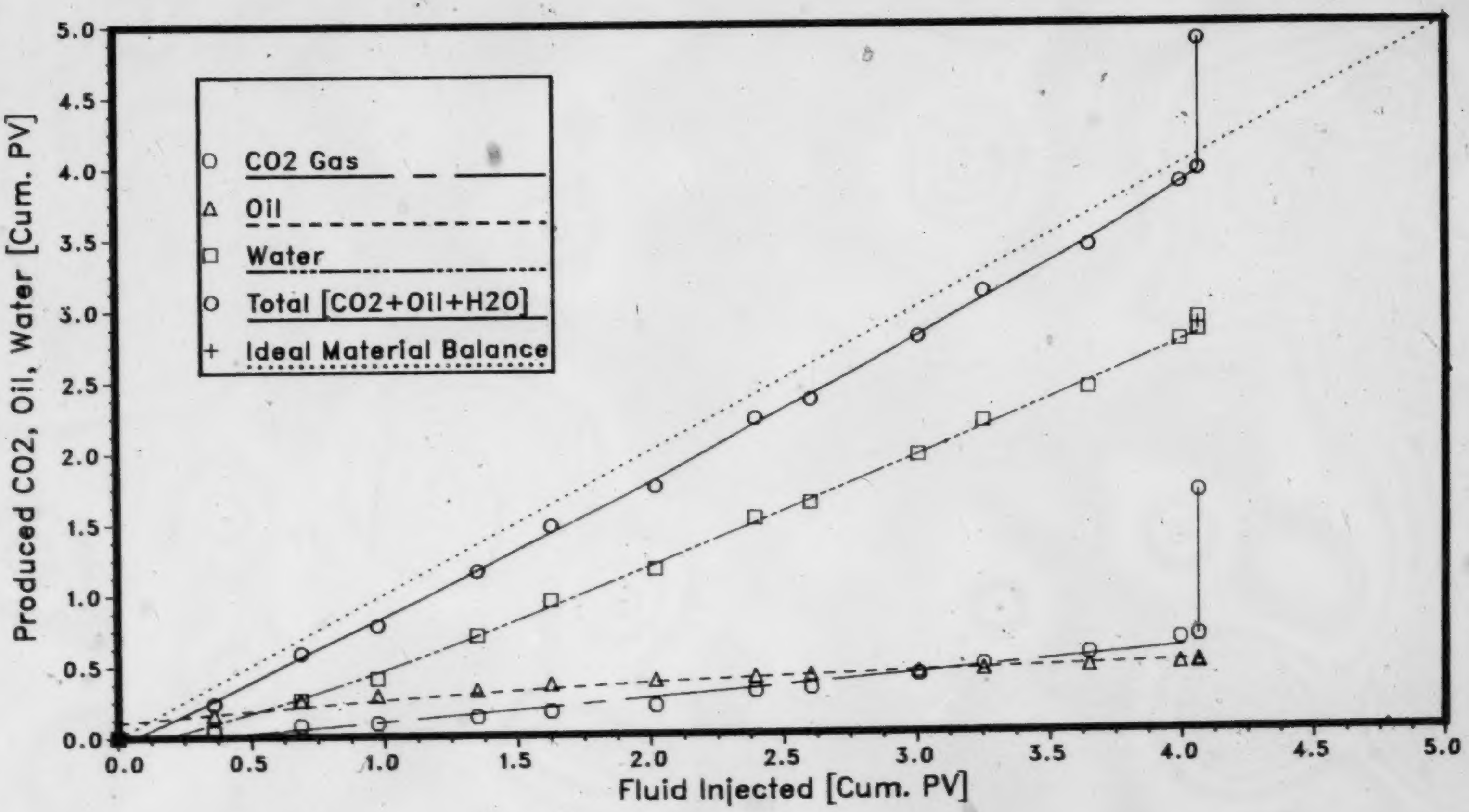
Figure B.3 Volumetric Balance on Run LC 3.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 36.32 %, k = 11.538 darcies, S_o = 89.29 %, S_{wc} = 10.71 %

[0.89 HCPV CO2 @ 1.00 MPa (0.39 g–mol) 4:1 WAG, 10–Slugs]

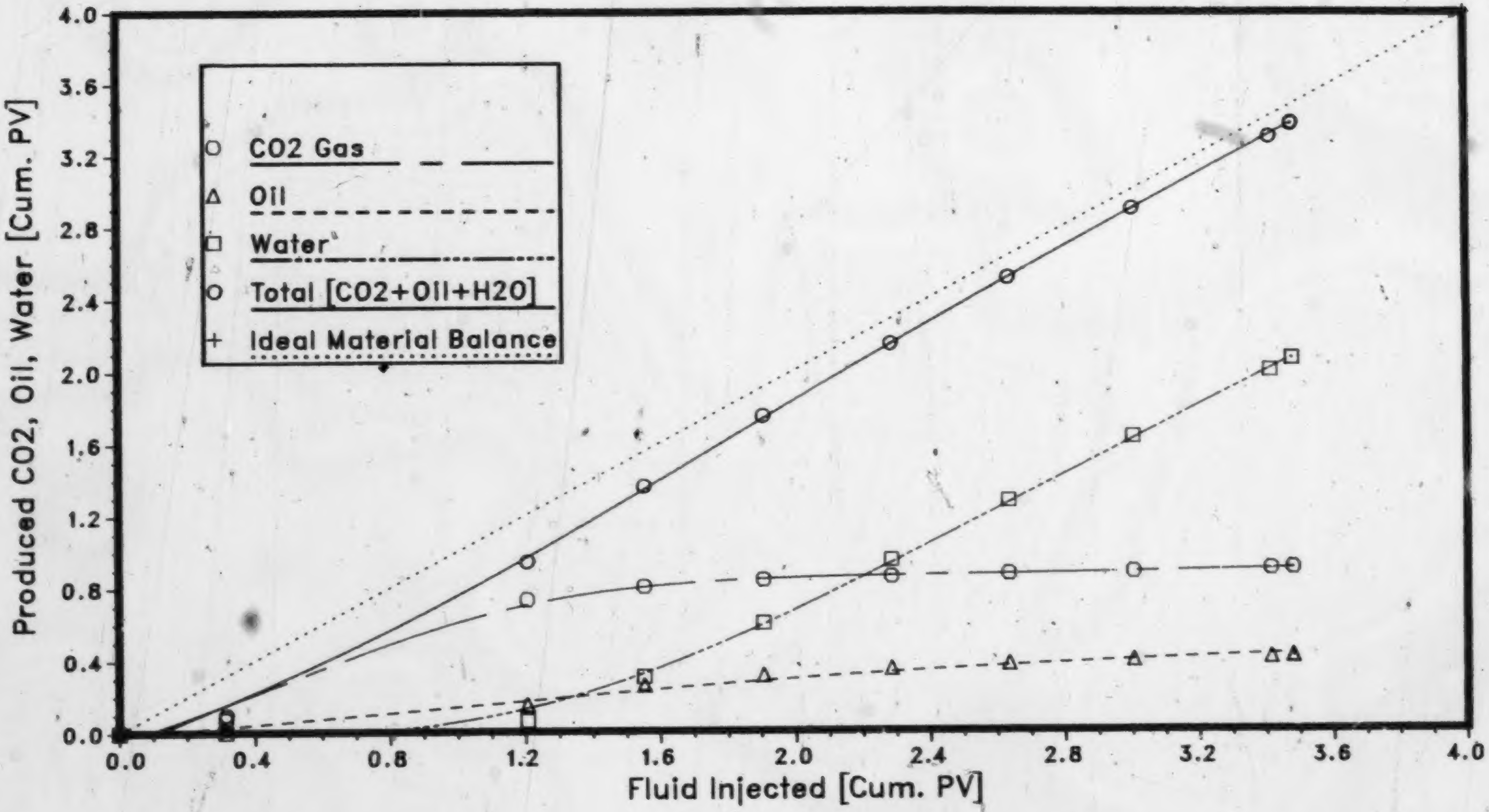
Figure B.4 Volumetric Balance on Run LC 4.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 35.63 %, k = 10.800 darcies, S_o = 90.10 %, S_{wc} = 9.90 %

[0.89 HCPV CO2 @ 1.00 MPa (0.39 g–mol) 4:1 WAG, 5–Slugs]

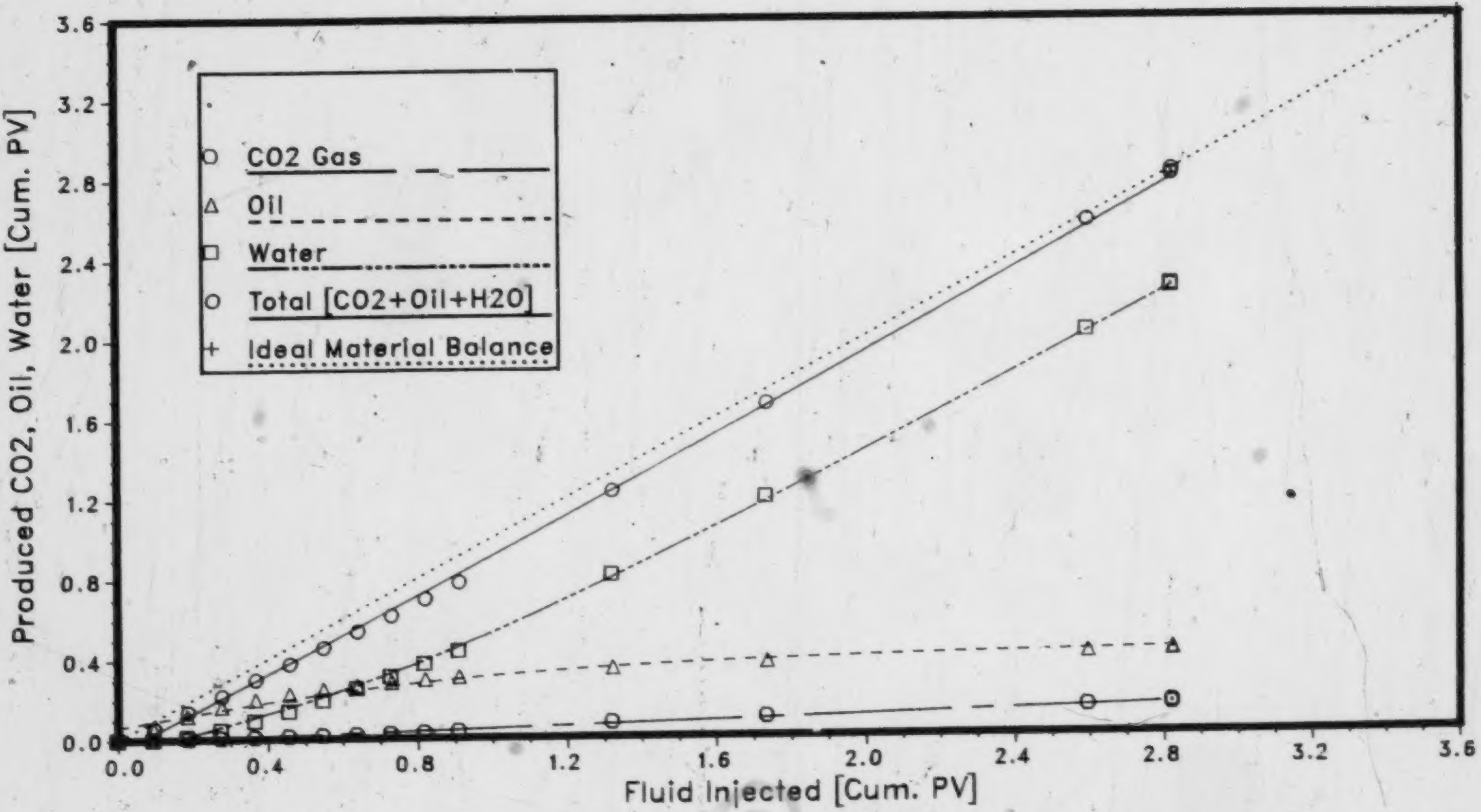
Figure B.5 Volumetric Balance on Run LC 5.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 34.09 %, k = 12.717 darcies, S_o = 89.24 %, S_{wc} = 10.76 %

[0.89 HCPV CO2 @ 1.00 MPa (0.39 g–mol) 4:1 WAG, 1–Slug]

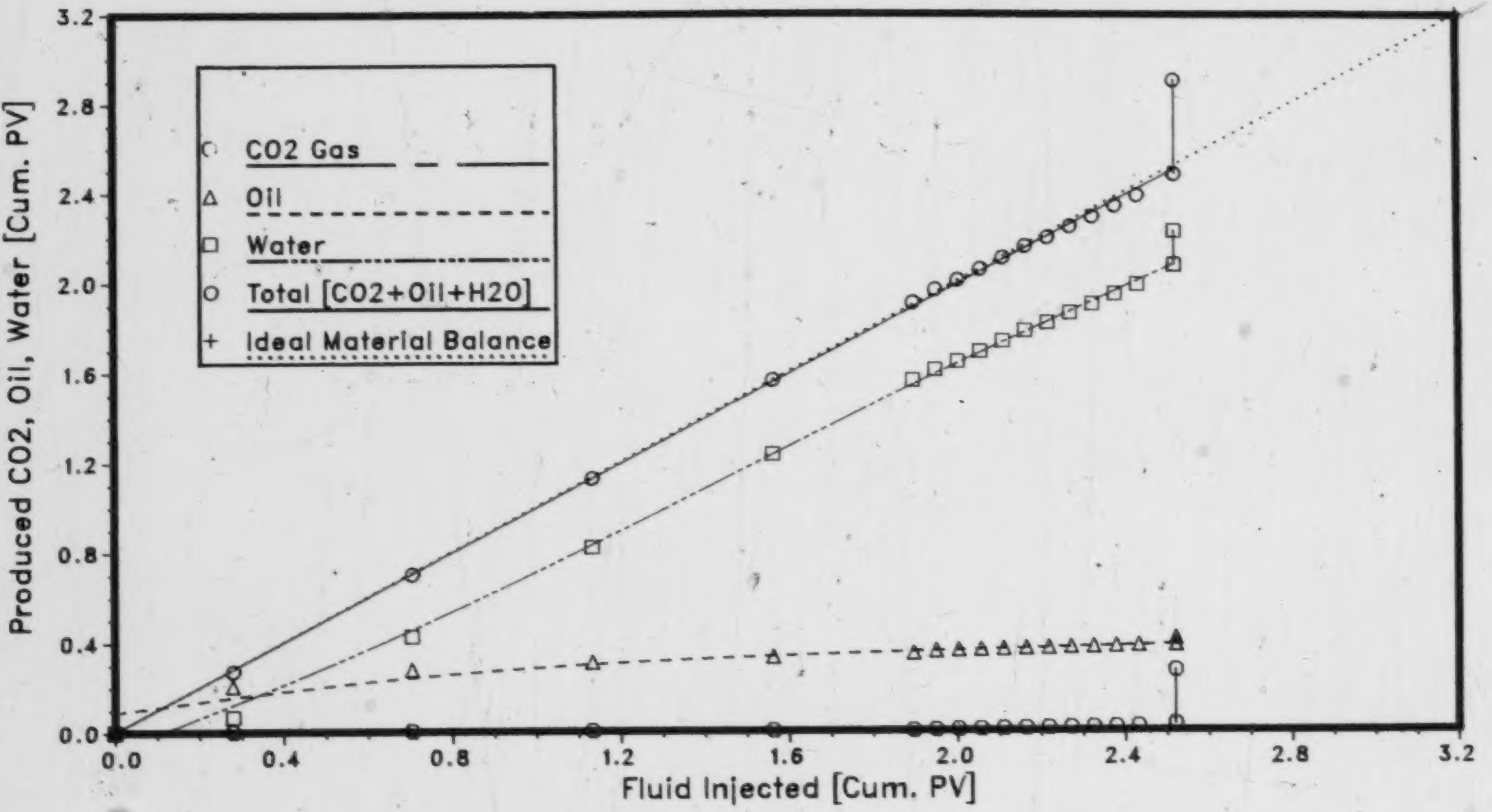
Figure B.6 Volumetric Balance on Run LC 6.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 34.80 %, k = 15.774 darcies, S_o = 90.58 %, S_{wc} = 9.42 %

[0.20 HCPV CO2 @ 1.00 MPa (0.08 g-mol) 4:1 WAG, 10-Slugs]

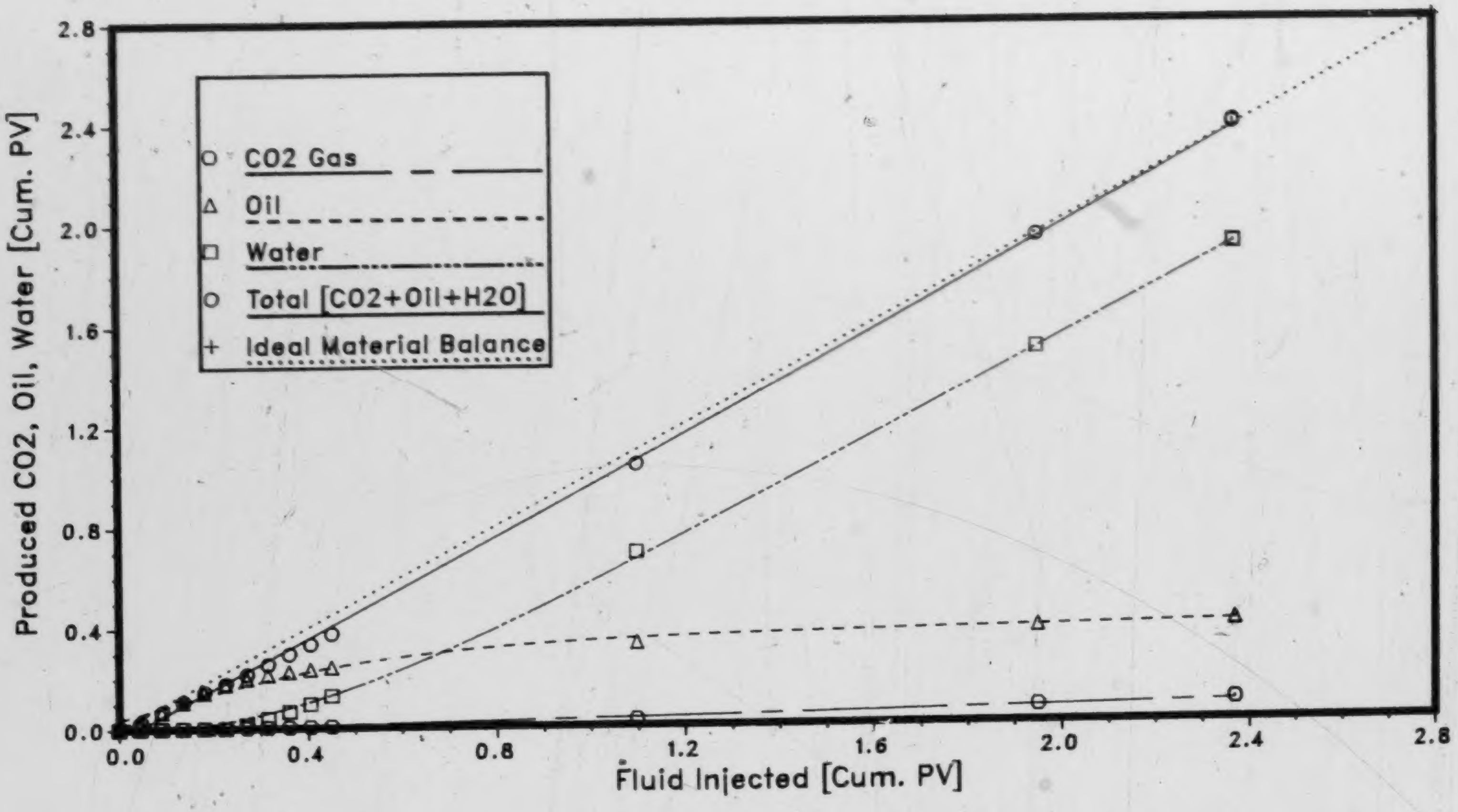
Figure B.7 Volumetric Balance on Run LC 7.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 37.05 %, k = 11.379 darcies, S_o = 89.69 %, S_{wc} = 10.31 %

[2.11 HCPV WF => 0.20 RHCPV CO2 @ 1.00 MPa (0.05 g-mol) 4:1 WAG]

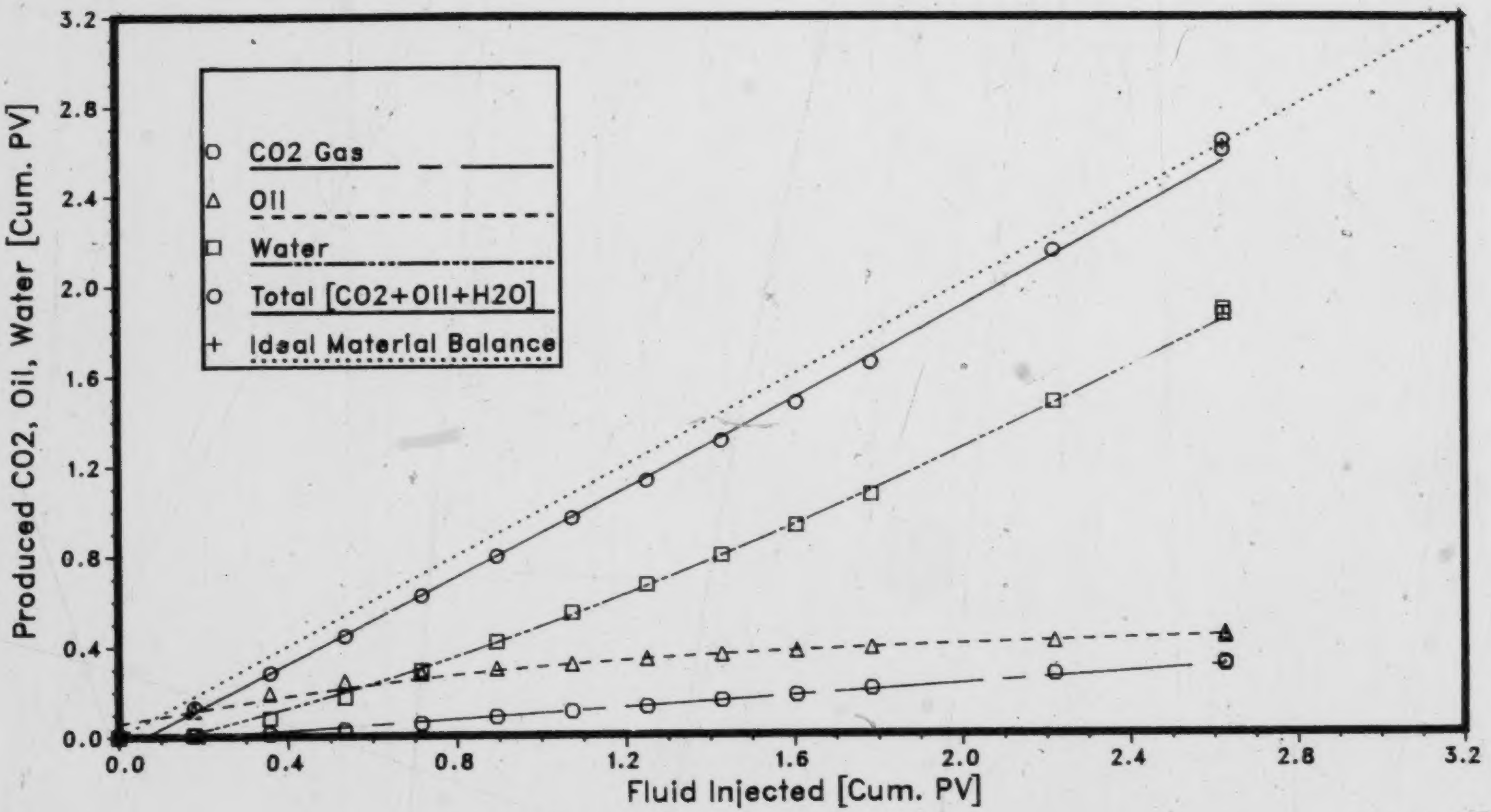
Figure B.8 Volumetric Balance on Run LC 8.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 36.73 %, k = 12.667 darcies, S_o = 90.04 %, S_{wc} = 9.96 %

[0.10 HCPV CO2 @ 1.00 MPa (0.04 g–mol) 4:1 WAG, 10–Slugs]

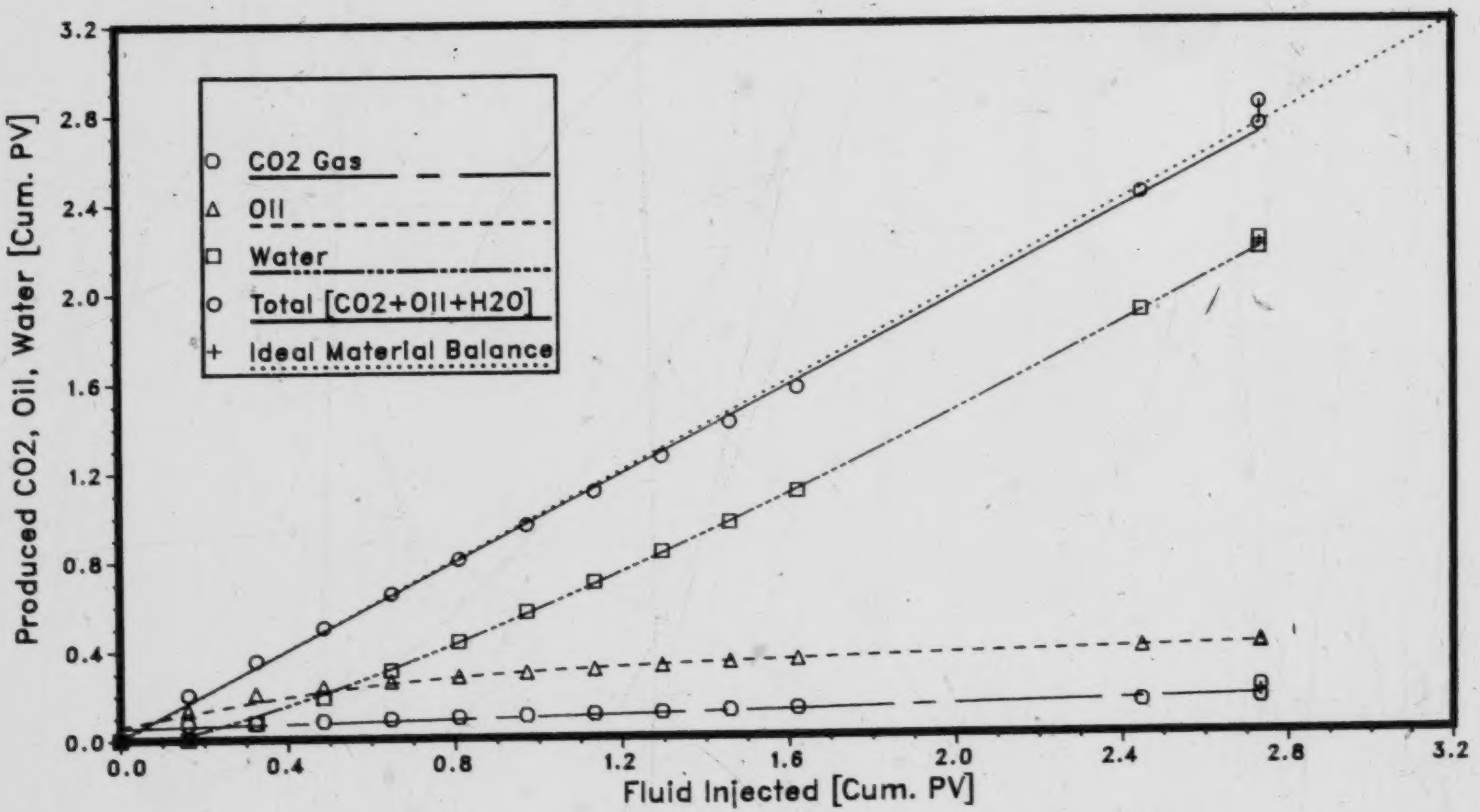
Figure B.9 Volumetric Balance on Run LC 9.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 35.77 %, k = 10.978 darcies, S_o = 88.93 %, S_{wc} = 11.07 %

[0.40 HCPV CO2 @ 1.00 MPa (0.17 g-mol) 4:1 WAG, 10-Slugs]

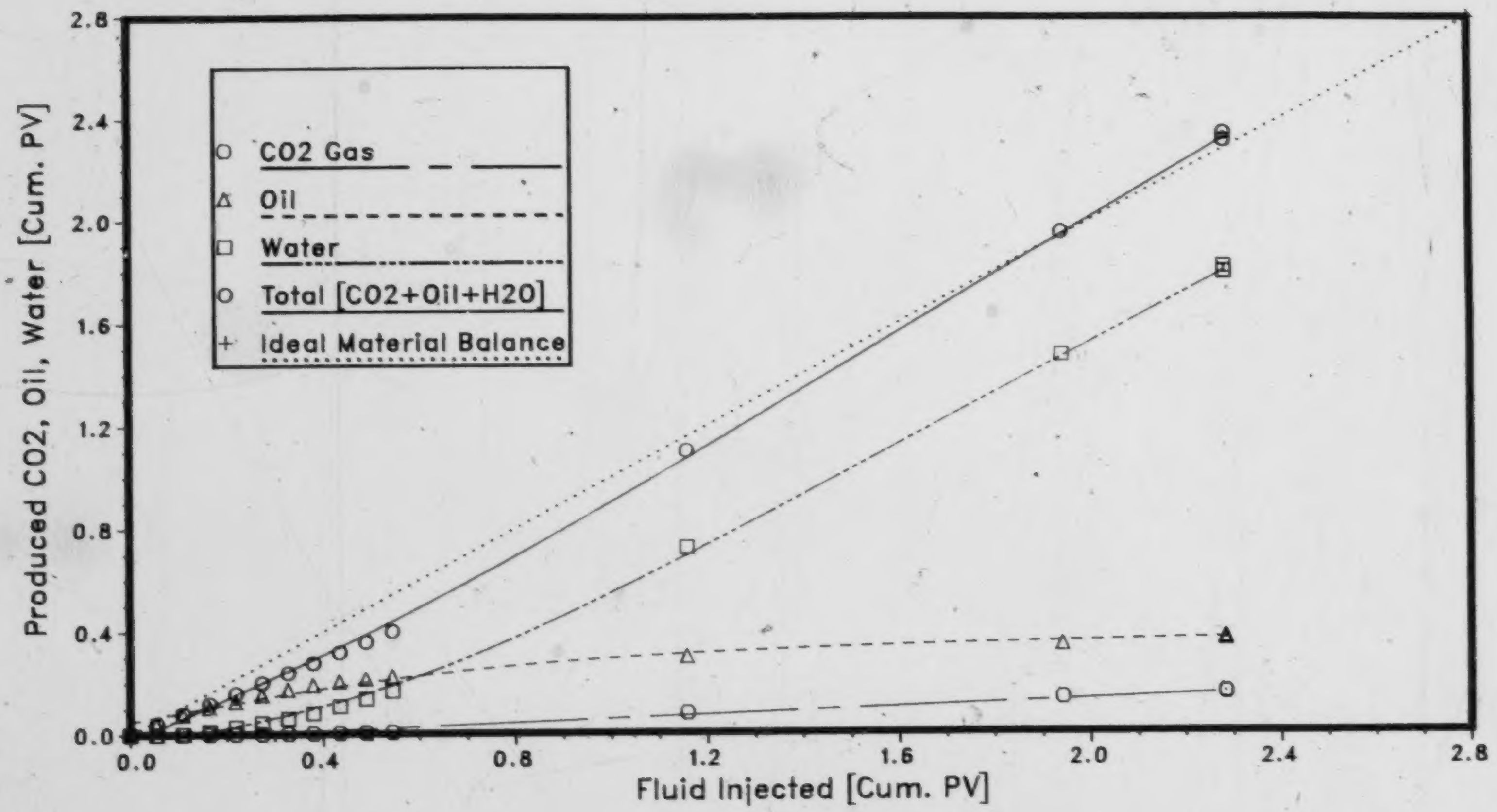
Figure B.10 Volumetric Balance on Run LC10.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 38.28 %, k = 13.998 darcies, S_o = 89.95 %, S_{wc} = 10.05 %

[0.20 HCPV CO2 @ 1.00 MPa (0.09 g–mol) 8:1 WAG, 10–Slugs]

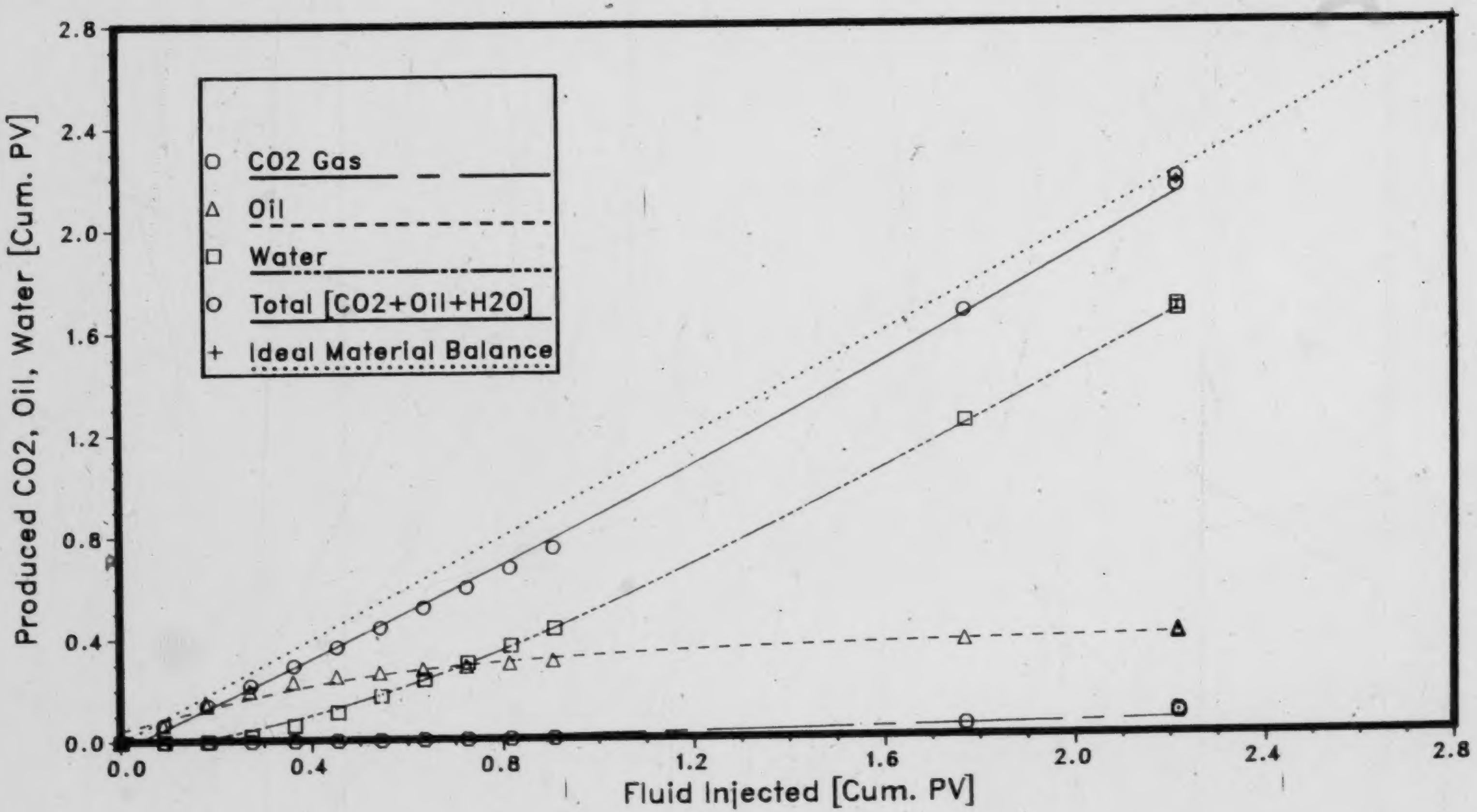
Figure B.11 Volumetric Balance on Run LC11.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 38.40 %, k = 16.156 darcies, S_o = 90.84 %, S_{wc} = 9.16 %

[0.20 HCPV CO2 @ 1.00 MPa (0.09 g-mol) 2:1 WAG, 10-Slugs]

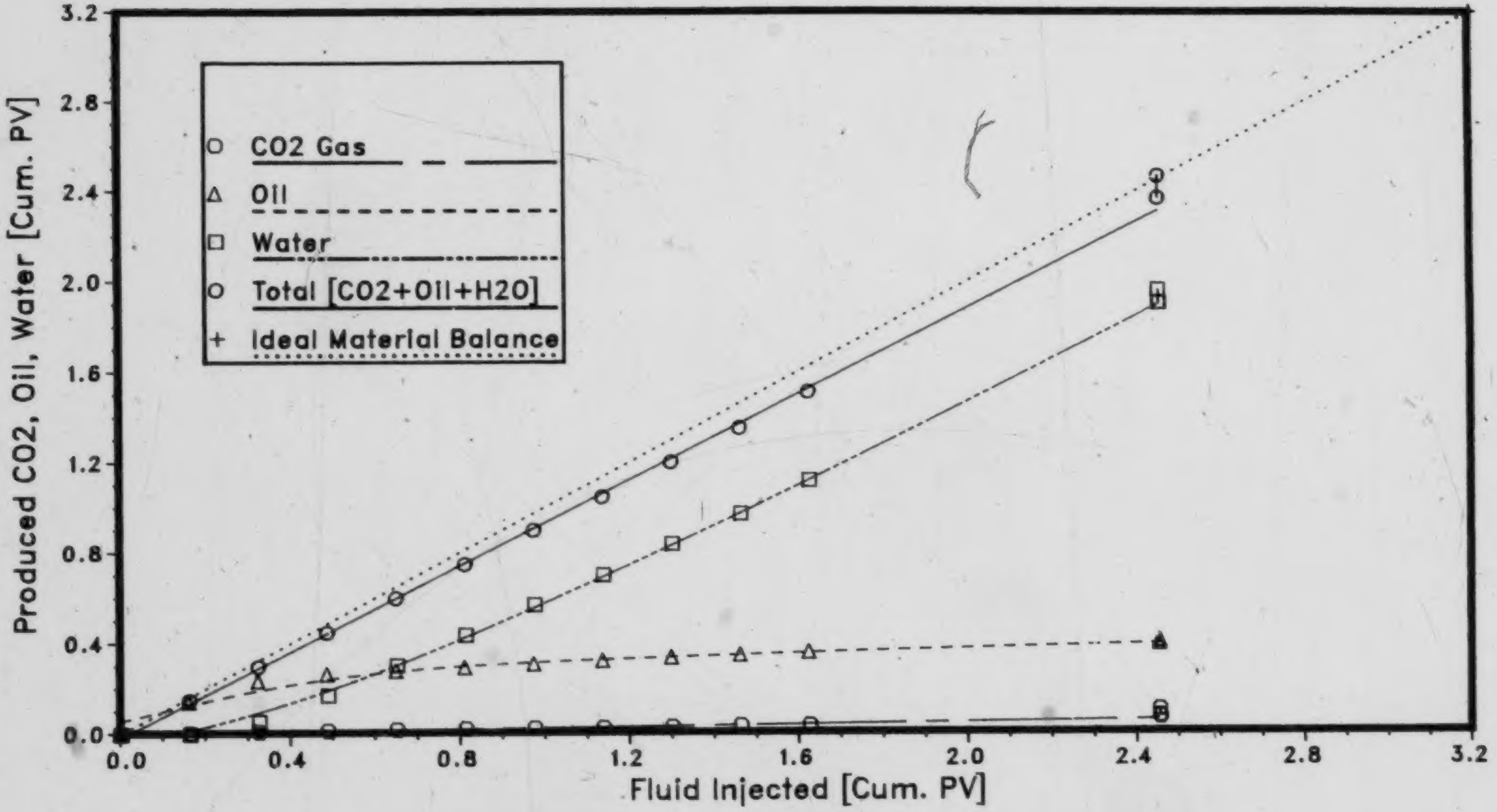
Figure B.12 Volumetric Balance on Run LC12.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.492 m/d, μ_o = 1055.3 mPa.s
ϕ = 36.22 %, k = 12.118 darcies, S_o = 90.51 %, S_{wc} = 9.49 %

[0.20 HCPV CO2 @ 1.00 MPa (0.09 g–mol) 4:1 WAG, 10–Slugs]

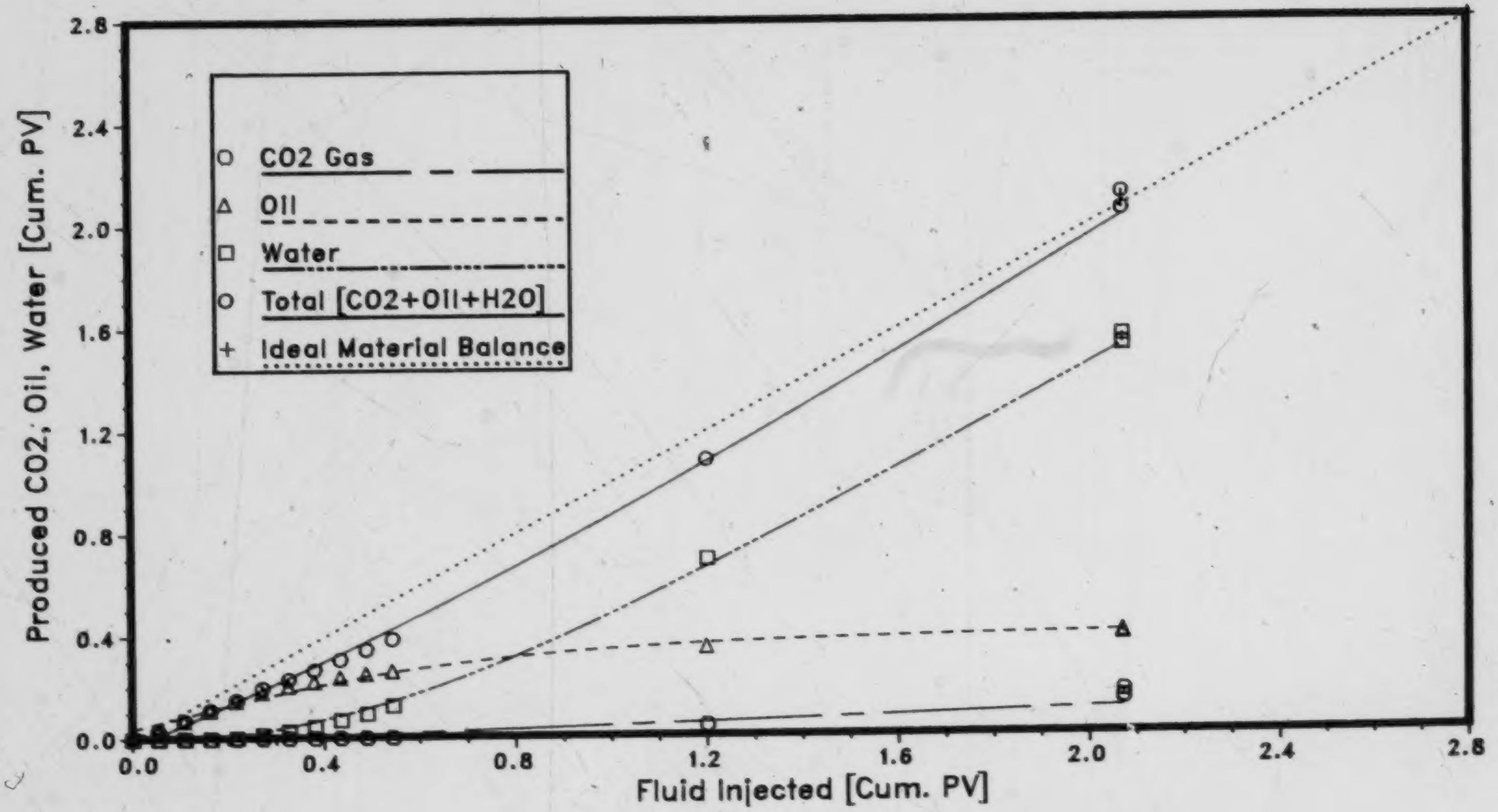
Figure **B.13** Volumetric Balance on Run LC13.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.492 m/d, μ_o = 1055.3 mPa.s
ϕ = 36.93 %, k = 12.047 darcies, S_o = 90.22 %, S_{wc} = 9.78 %

[0.20 HCPV CO2 @ 1.00 MPa (0.09 g-mol) 8:1 WAG, 10-Slugs]

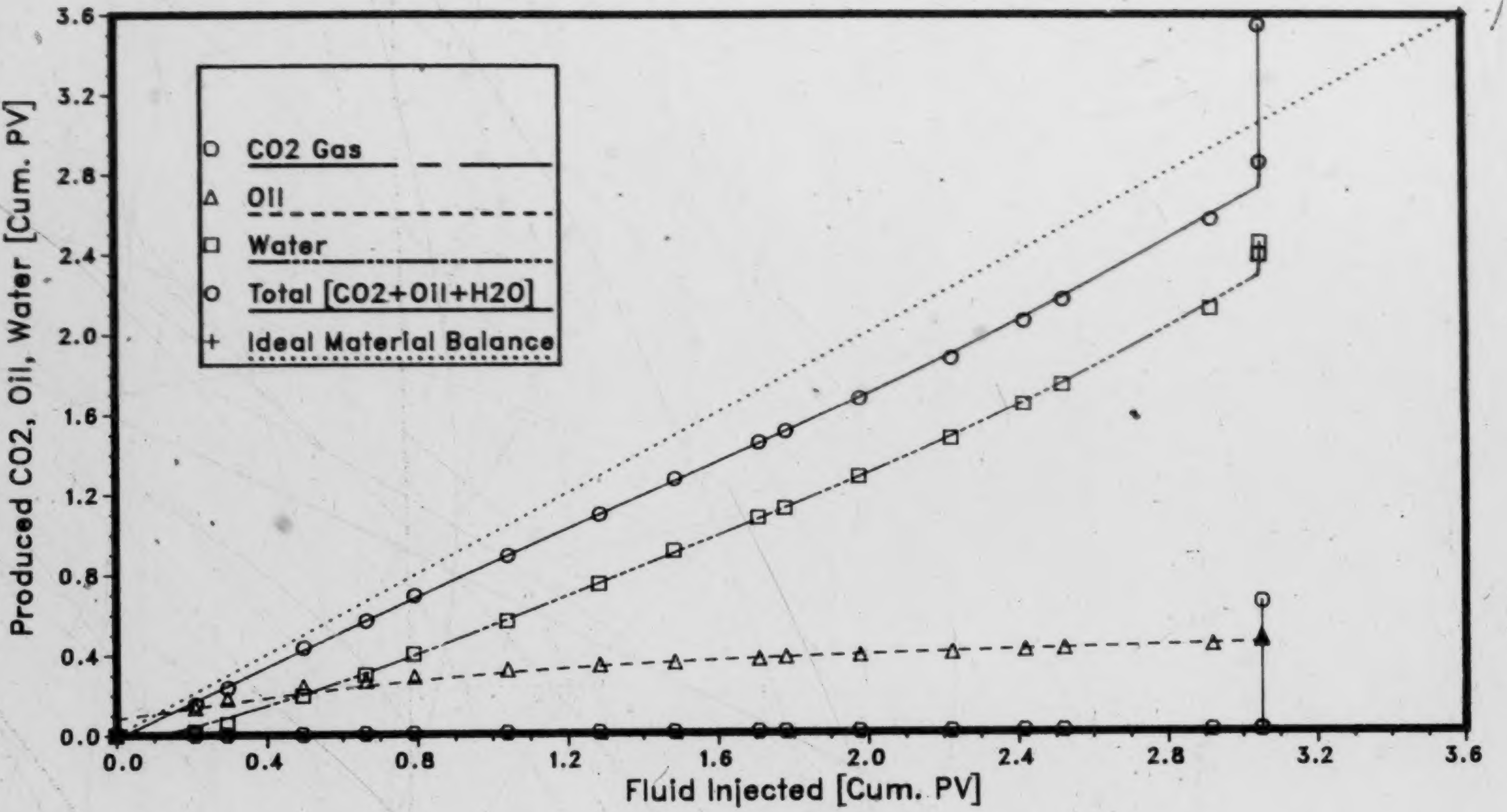
Figure B.14 Volumetric Balance on Run LC14.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.492 m/d, μ_o = 1055.3 mPa.s
ϕ = 36.57 %, k = 12.056 darcies, S_o = 90.28 %, S_{wc} = 9.72 %

[0.20 HCPV CO2 @ 1.00 MPa (0.09 g–mol) 2:1 WAG, 10–Slugs]

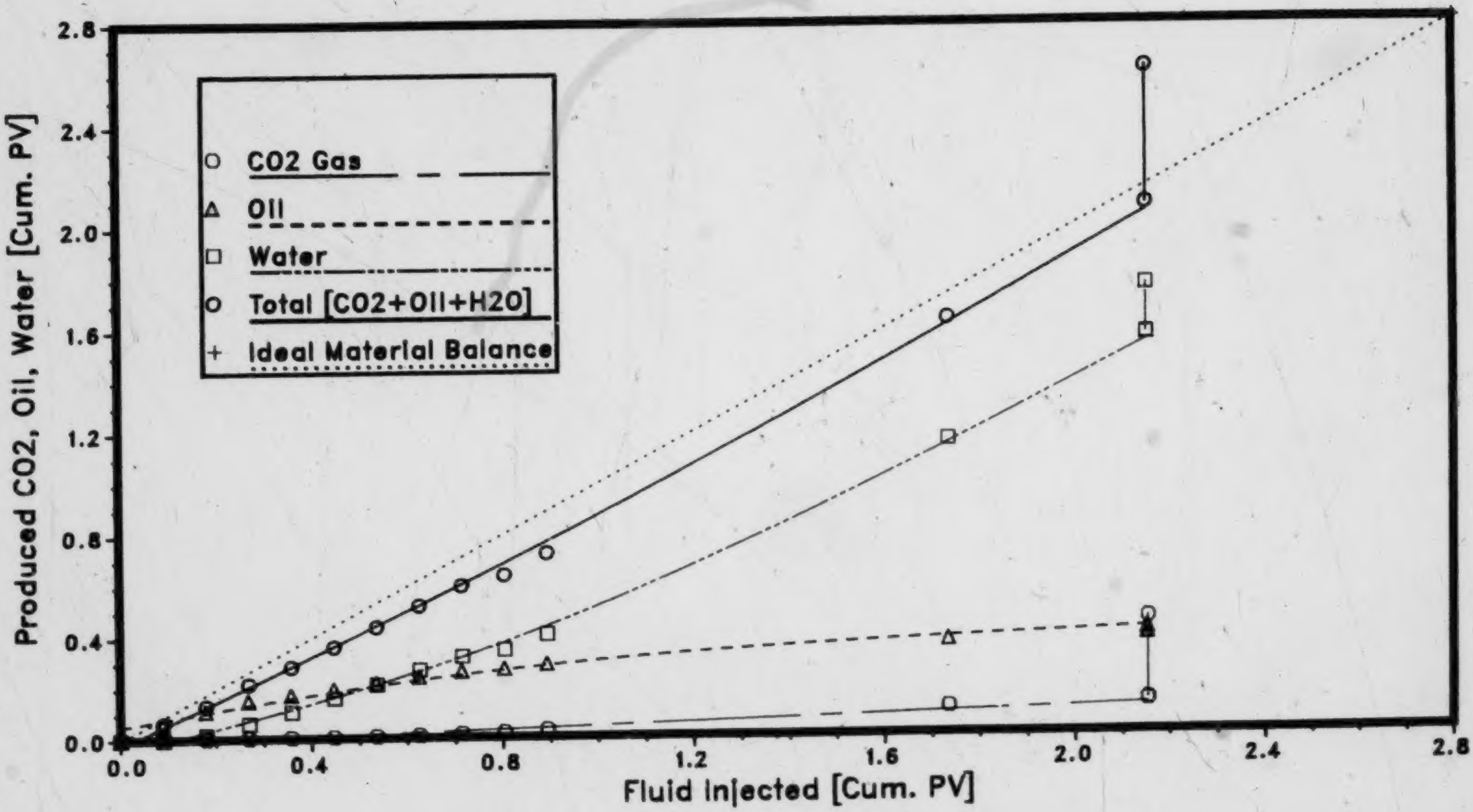
Figure B.15 Volumetric Balance on Run LC15.



NOTE: Average Run Conditions: Direct Line Drive, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1059.0 mPa.s
ϕ = 34.77 %, k = 9.025 darcies, S_o = 79.11 %, S_{wc} = 20.89 %

[0.64 HCPV CO2 @ 2.50 MPa (0.75 g–mol) 4:1 WAG, 10–Slugs]

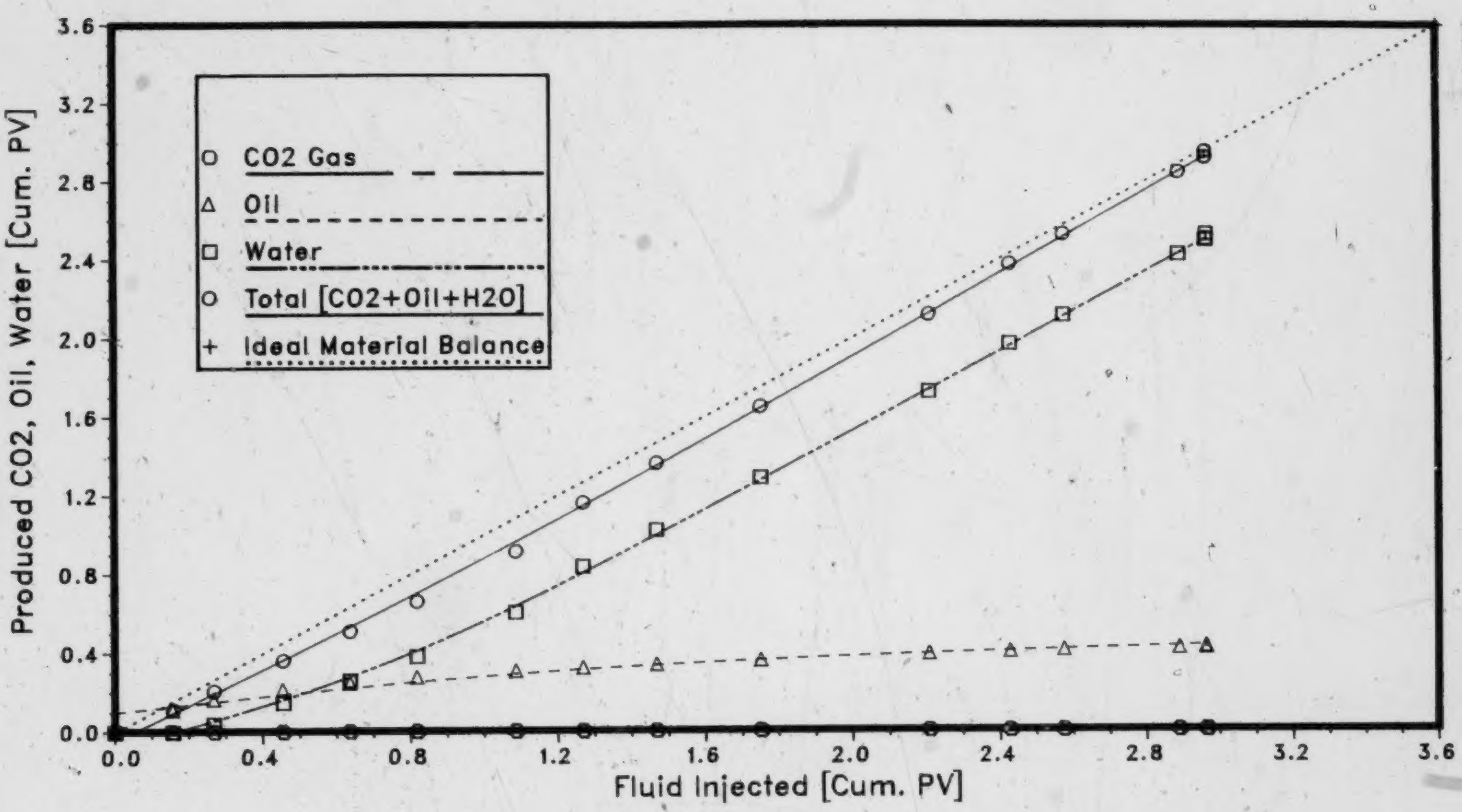
Figure B.16 Volumetric Balance on Run LC16.



NOTE: Average Run Conditions: Direct Line Drive, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 37.70 %, k = 12.304 darcies, S_o = 89.16 %, S_{wc} = 10.84 %

[0.20 HCPV CO2 @ 2.50 MPa (0.26 g-mol) 4:1 WAG, 10-Slugs]

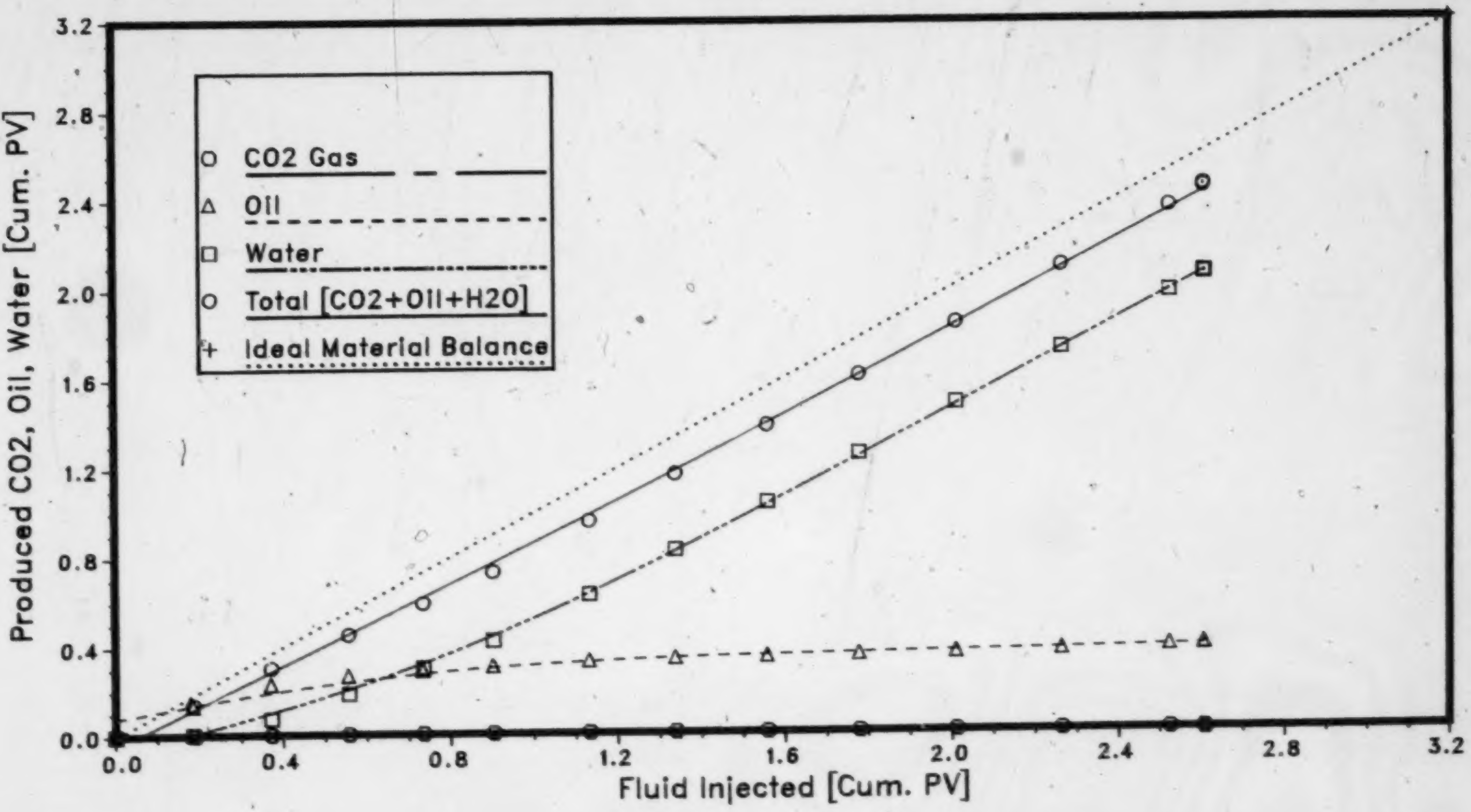
Figure B.17 Volumetric Balance on Run LC17.



NOTE: Average Run Conditions: Direct Line Drive, 5.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1059.0 mPa.s
ϕ = 33.31 %, k = 5.912 darcies, S_o = 89.72 %, S_{wc} = 10.28 %

[0.21 HCPV CO2 @ 5.50 MPa (0.74 g-mol) 4:1 WAG, 10-Slugs]

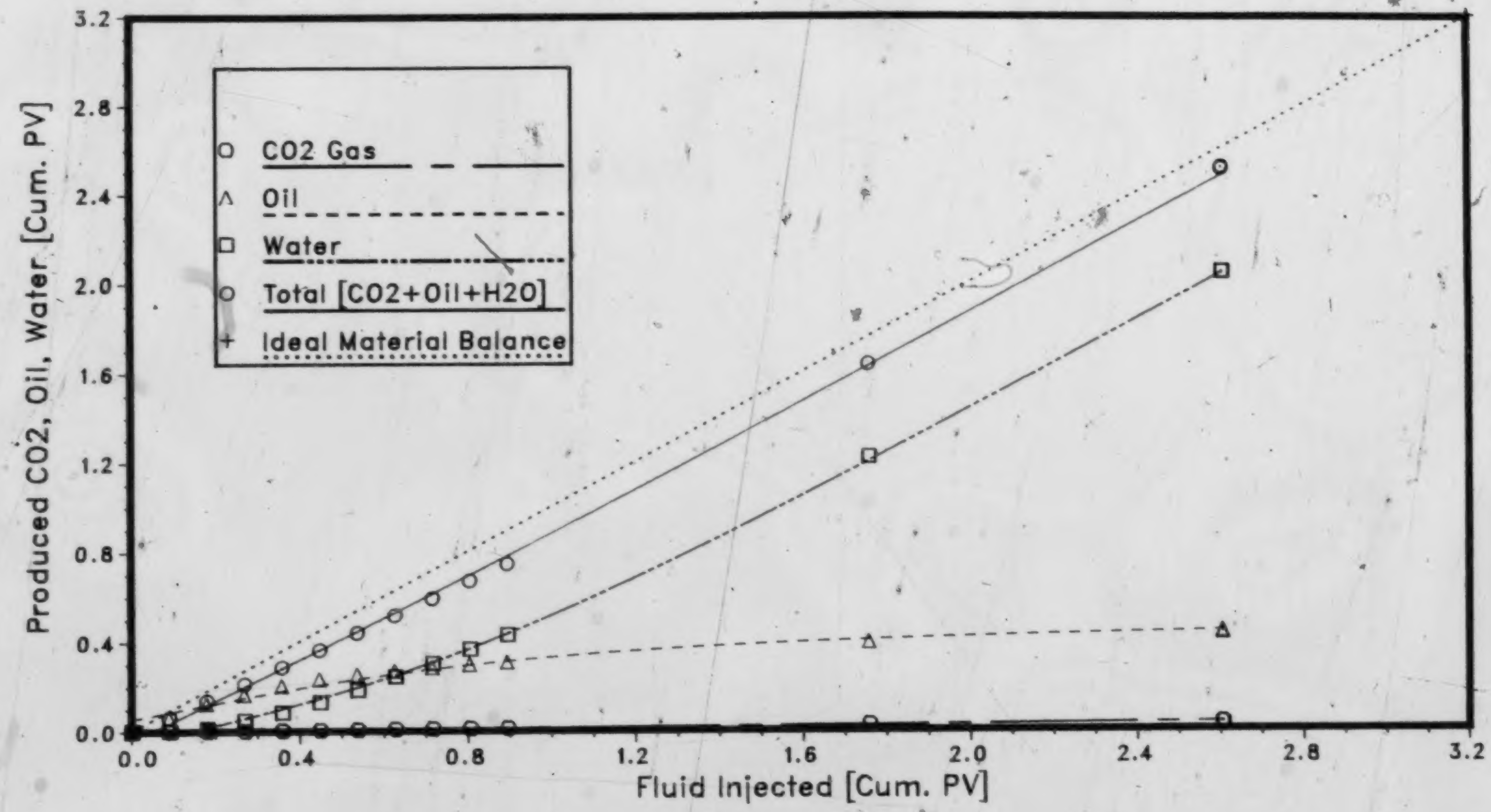
Figure **B.18** Volumetric Balance on Run LC18.



NOTE: Average Run Conditions: Direct Line Drive, 5.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1059.0 mPa.s
ϕ = 34.41 %, k = 12.363 darcies, S_o = 89.22 %, S_{wc} = 10.78 %

[0.20 HCPV CO2 @ 5.50 MPa (0.70 g-mol) 4:1 WAG, 10-Slugs]

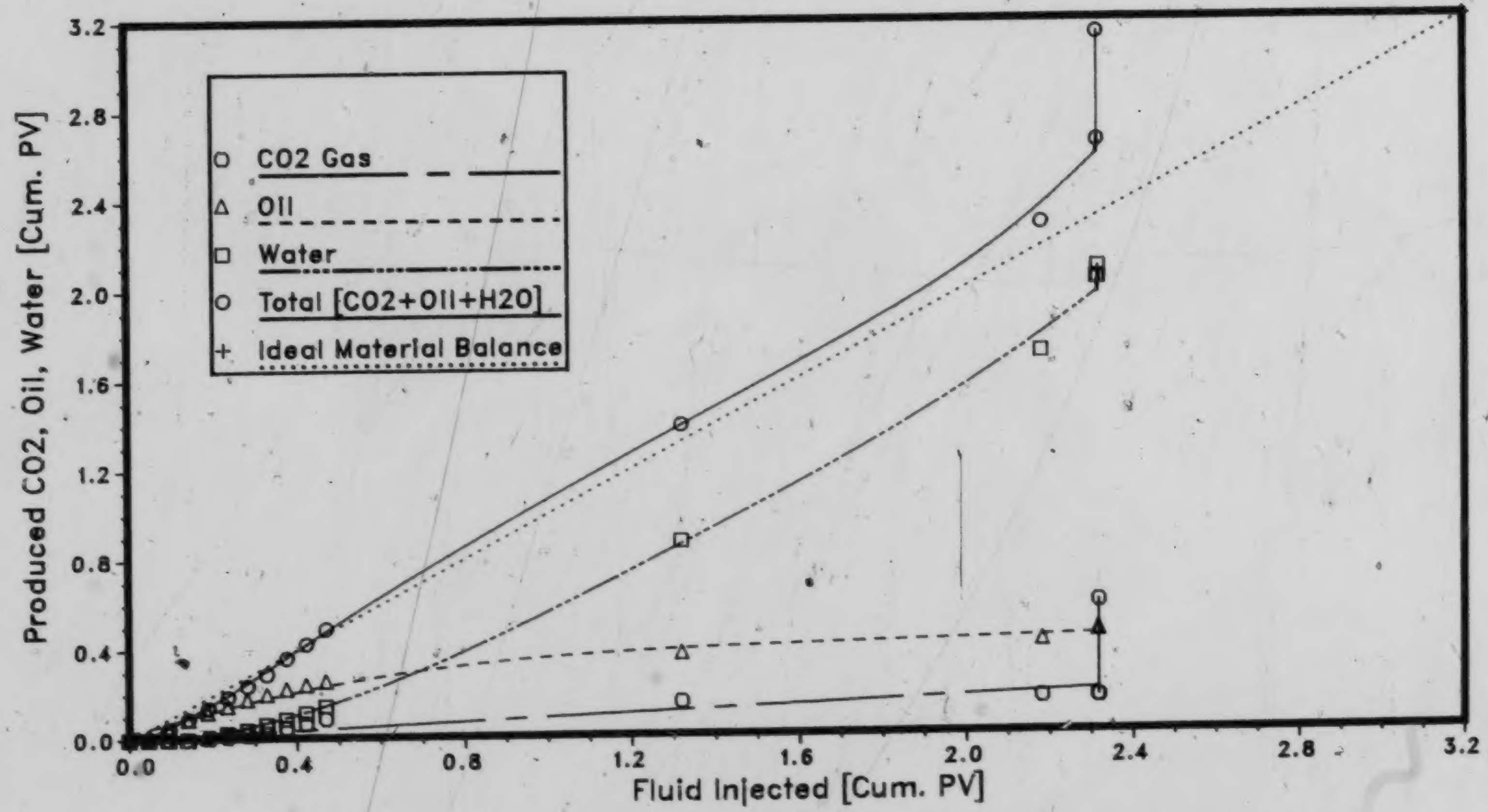
Figure B.19 Volumetric Balance on Run LC19.



NOTE: Average Run Conditions: Direct Line Drive, 5.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 35.77 %, k = 12.451 darcies, S_o = 89.34 %, S_{wc} = 10.66 %

[0.20 HCPV CO2 @ 5.50 MPa (0.78 g–mol) 4:1 WAG, 10–Slugs]

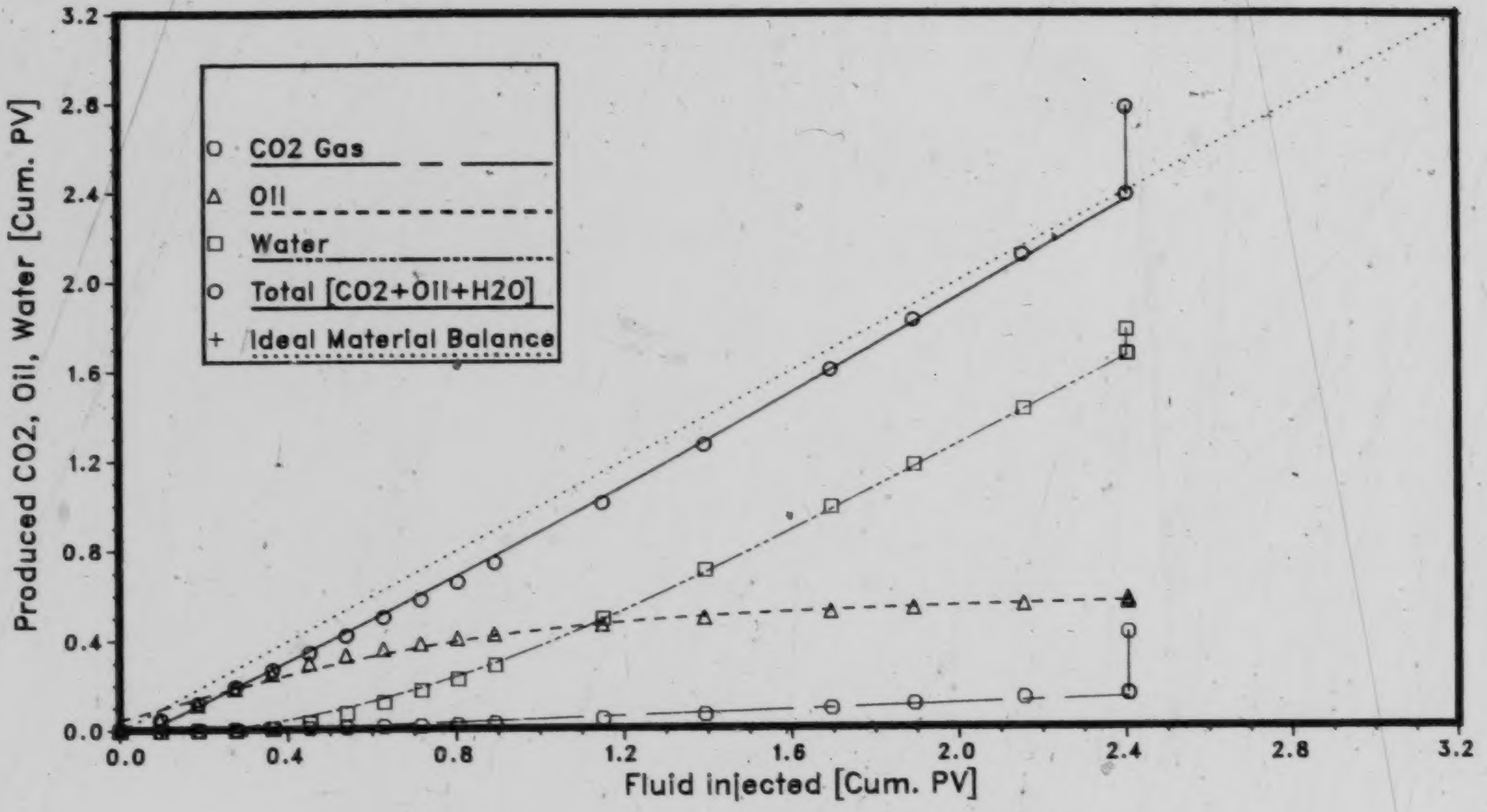
Figure B. 20 Volumetric Balance on Run LC20.



NOTE: Average Run Conditions: Direct Line Drive, 5.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 36.69 %, k = 15.095 darcies, S_o = 93.95 %, S_{wc} = 6.05 %

[0.10 HCPV CO2 @ 5.50 MPa (0.42 g–mol) 4:1 WAG, 10–Slugs]

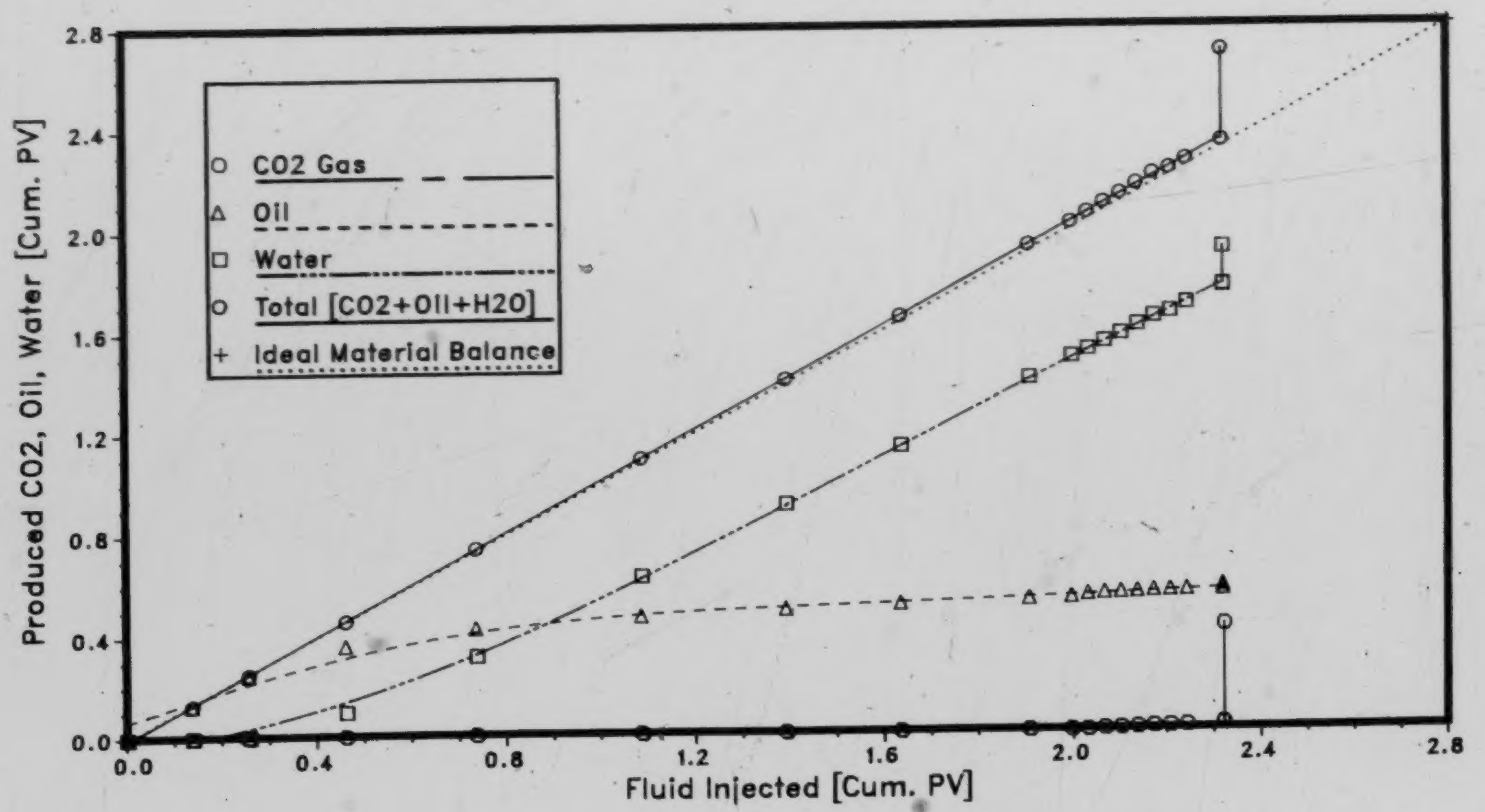
Figure **B.21** Volumetric Balance on Run LC21.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 150.0 mPa.s
ϕ = 36.67 %, k = 11.414 darcies, S_o = 88.20 %, S_{wc} = 11.80 %

[0.20 HCPV CO2 @ 1.00MPa (0.09 g−mol) 4:1 WAG, 10−Slugs, Wainwright]

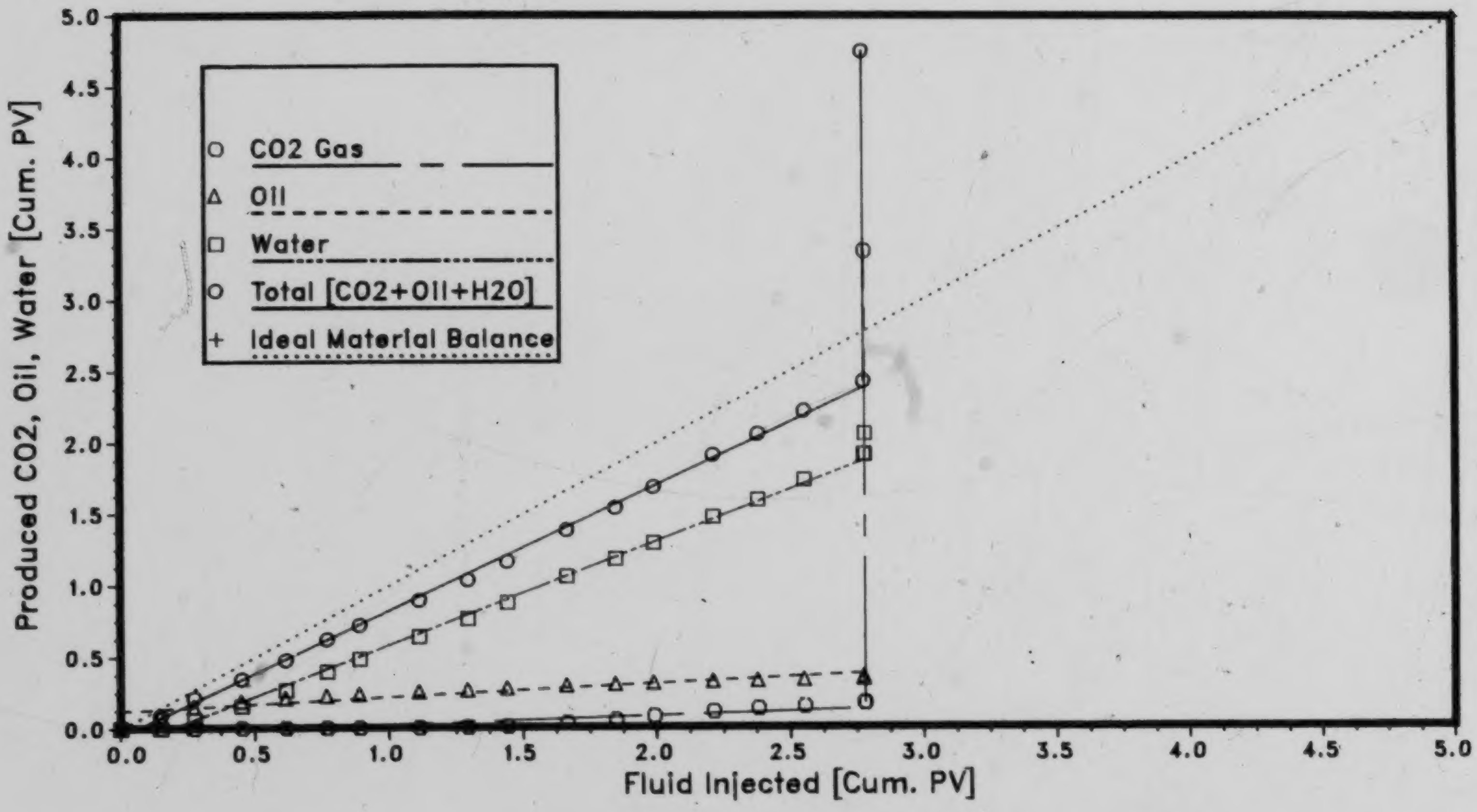
Figure B.22 Volumetric Balance on Run LC22.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 150.0 mPa.s
ϕ = 36.22 %, k = 11.457 darcies, S_o = 87.05 %, S_{wc} = 12.95 %

[2.29HCPV WF=>0.20 RHCPV CO2 @ 1.0 MPa(0.05 g-mol)4:1WAG,Wainwright]

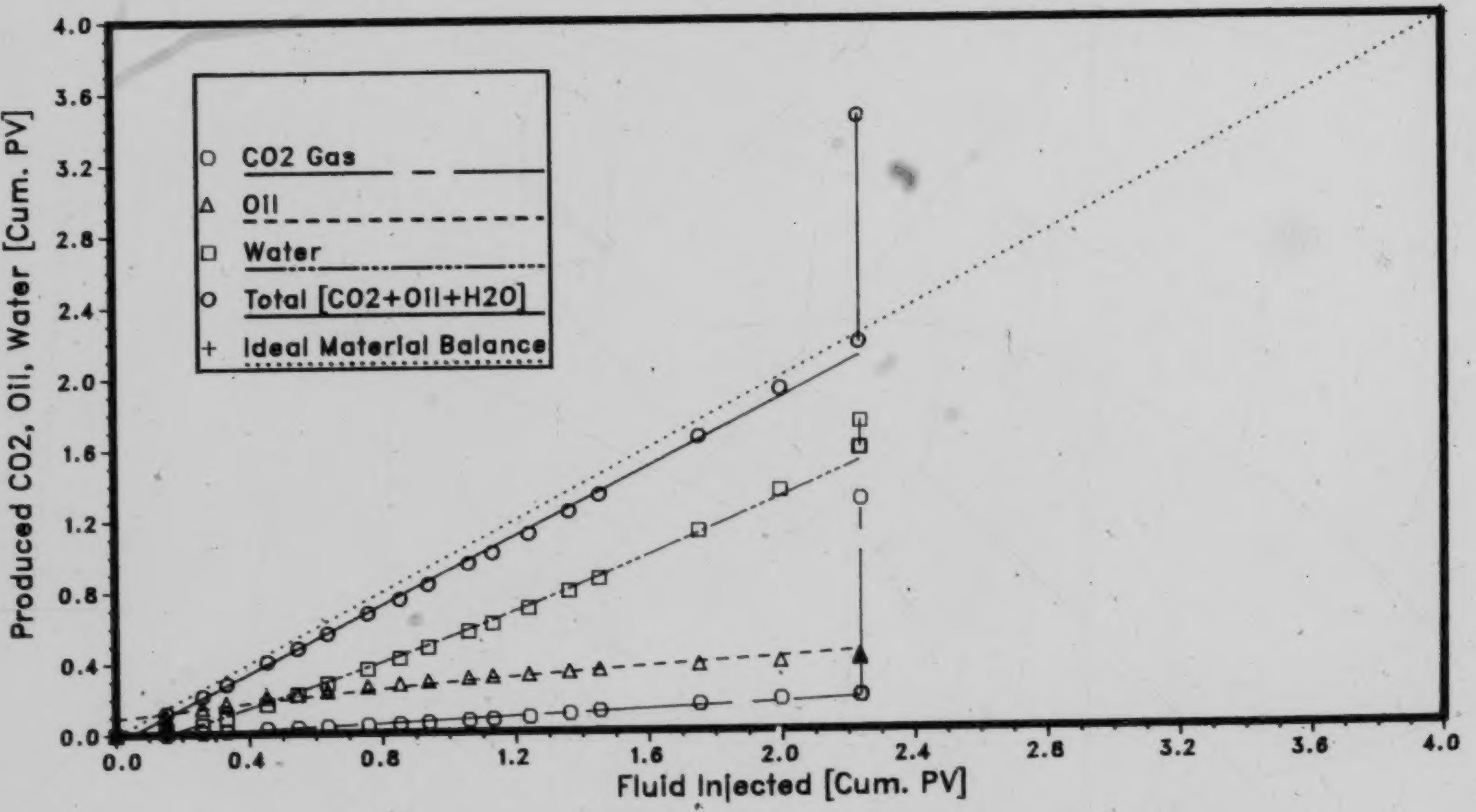
Figure B. 23 Volumetric Balance on Run LC23.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.776 m/d, μ_o = 3295.0 mPa.s
ϕ = 43.12 %, k = 7.617 darcies, S_o = 86.76 %, S_{wc} = 13.24 %

[0.61 HCPV CO2 @ 2.50 MPa (1.41 g–mol) 4:1 WAG, 10–Slugs, SENLAC]

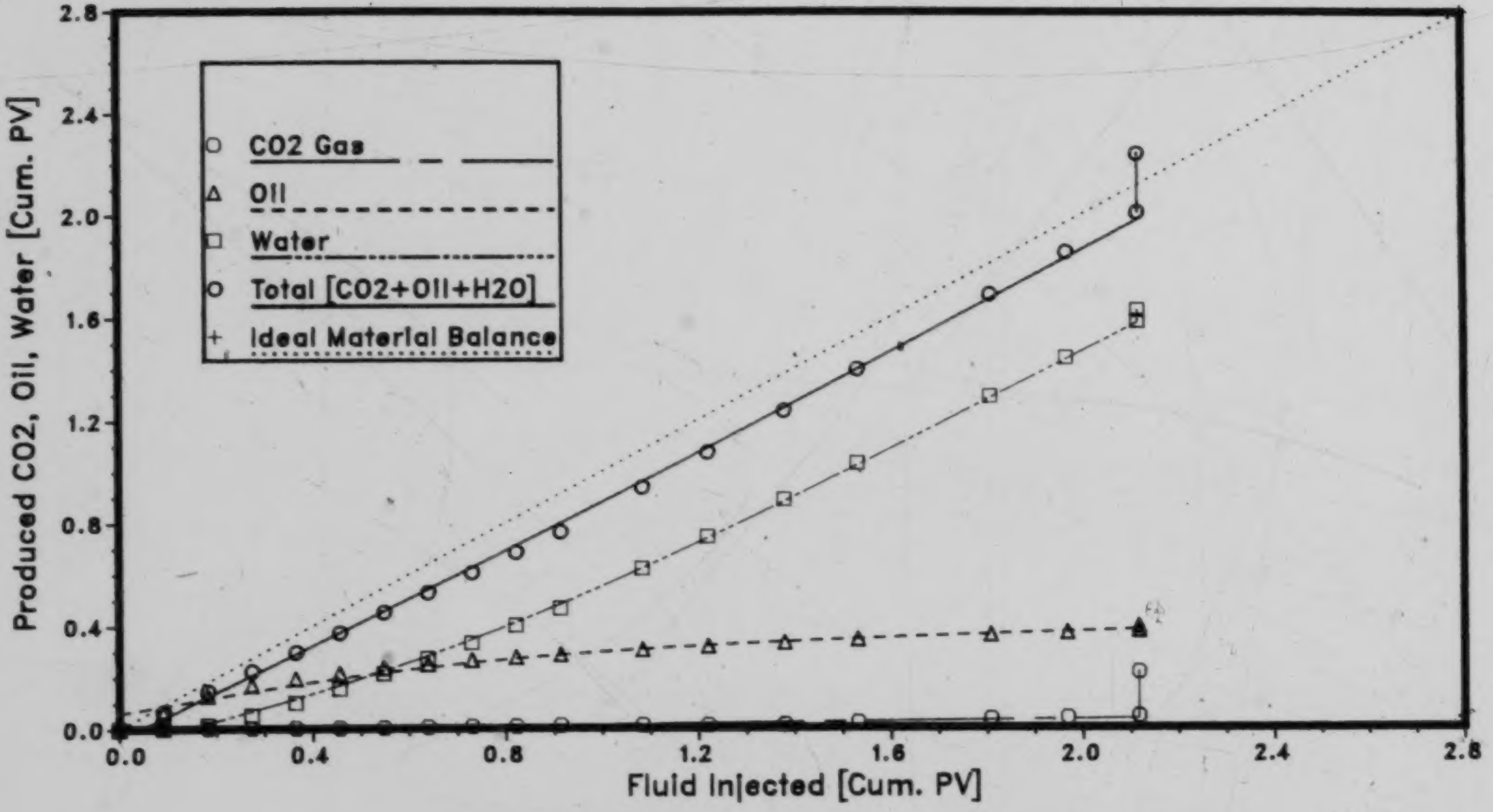
Figure B.24 Volumetric Balance on Run TD 1.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 4.10 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.776 m/d, μ_o = 3295.0 mPa.s
ϕ = 41.52 %, k = 7.405 darcies, S_o = 90.10 %, S_{wc} = 9.90 %

[0.33 HCPV CO2 @ 4.10 MPa (1.41 g–mol) 4:1 WAG, 10–Slugs, SENLAC]

Figure B.25 Volumetric Balance on Run TD 2.



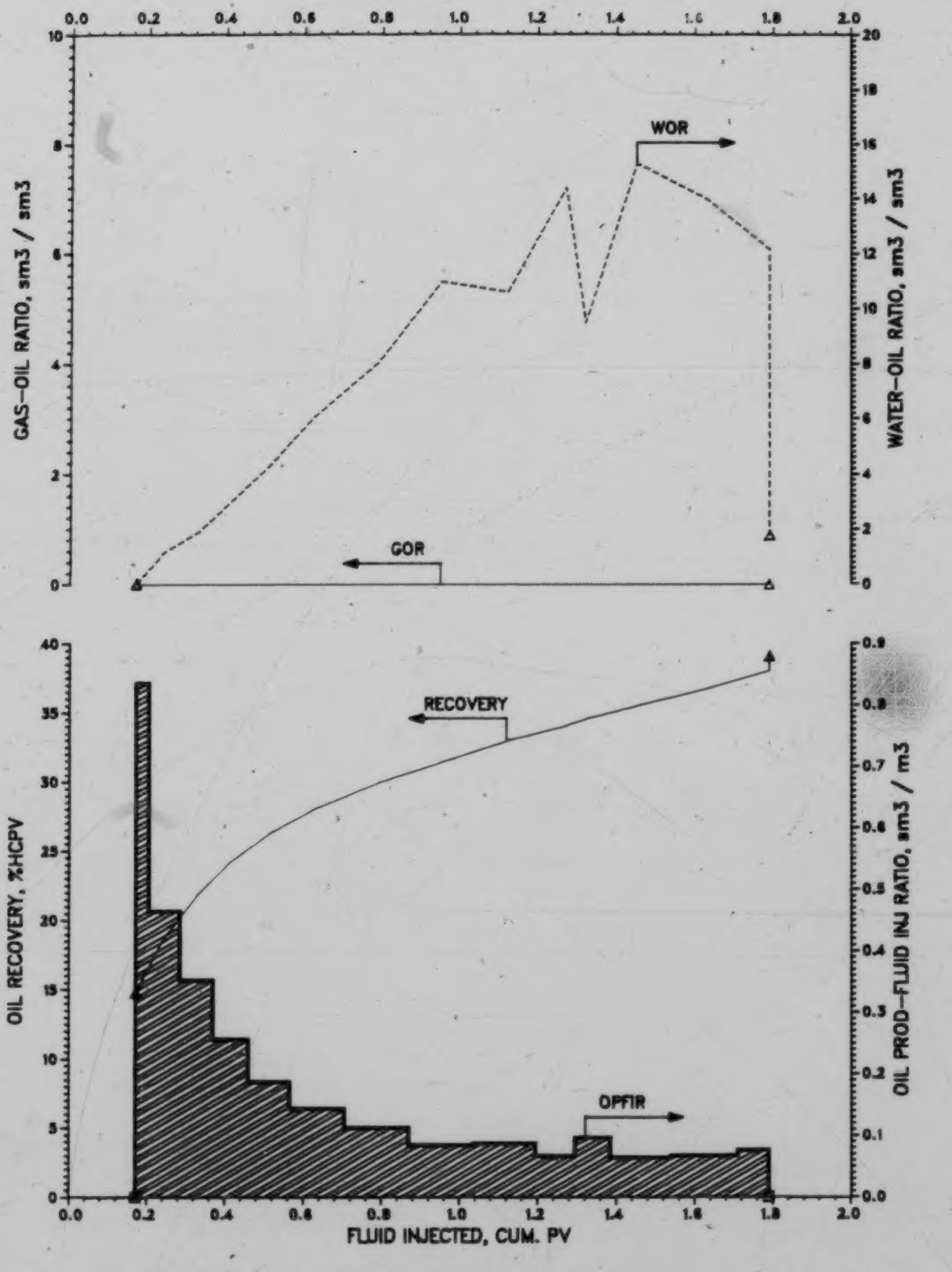
NOTE: Average Run Conditions: Quarter of a 5–Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.831 m/d, μ_o = 1055.3 mPa.s
ϕ = 40.59 %, k = 13.312 darcies, S_o = 91.33 %, S_{wc} = 8.67 %

[0.20 HCPV CO2 @ 1.00 MPa (0.16 g–mol) 4:1 WAG, 10–Slugs]

Figure B.26 – Volumetric Balance on Run TD 3.

Appendix C

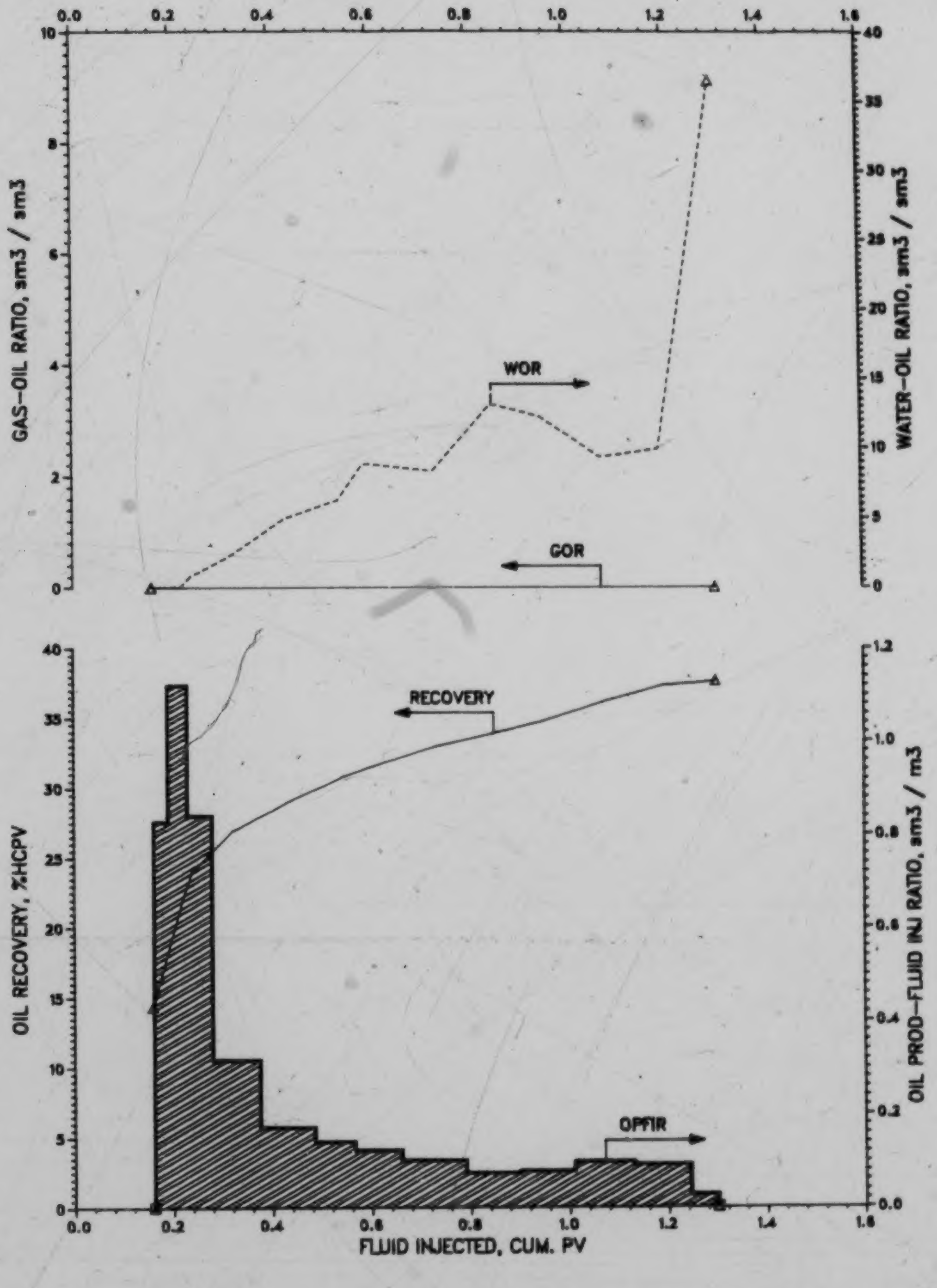
Production Histories of all Runs in Graphical Form



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1059.0 mPa.s
ϕ = 35.00 %, k = 11.100 darcies, S_o = 93.00 %, S_{wc} = 7.00 %

[1.92 HCPV Waterflood @ 1.00 MPa]

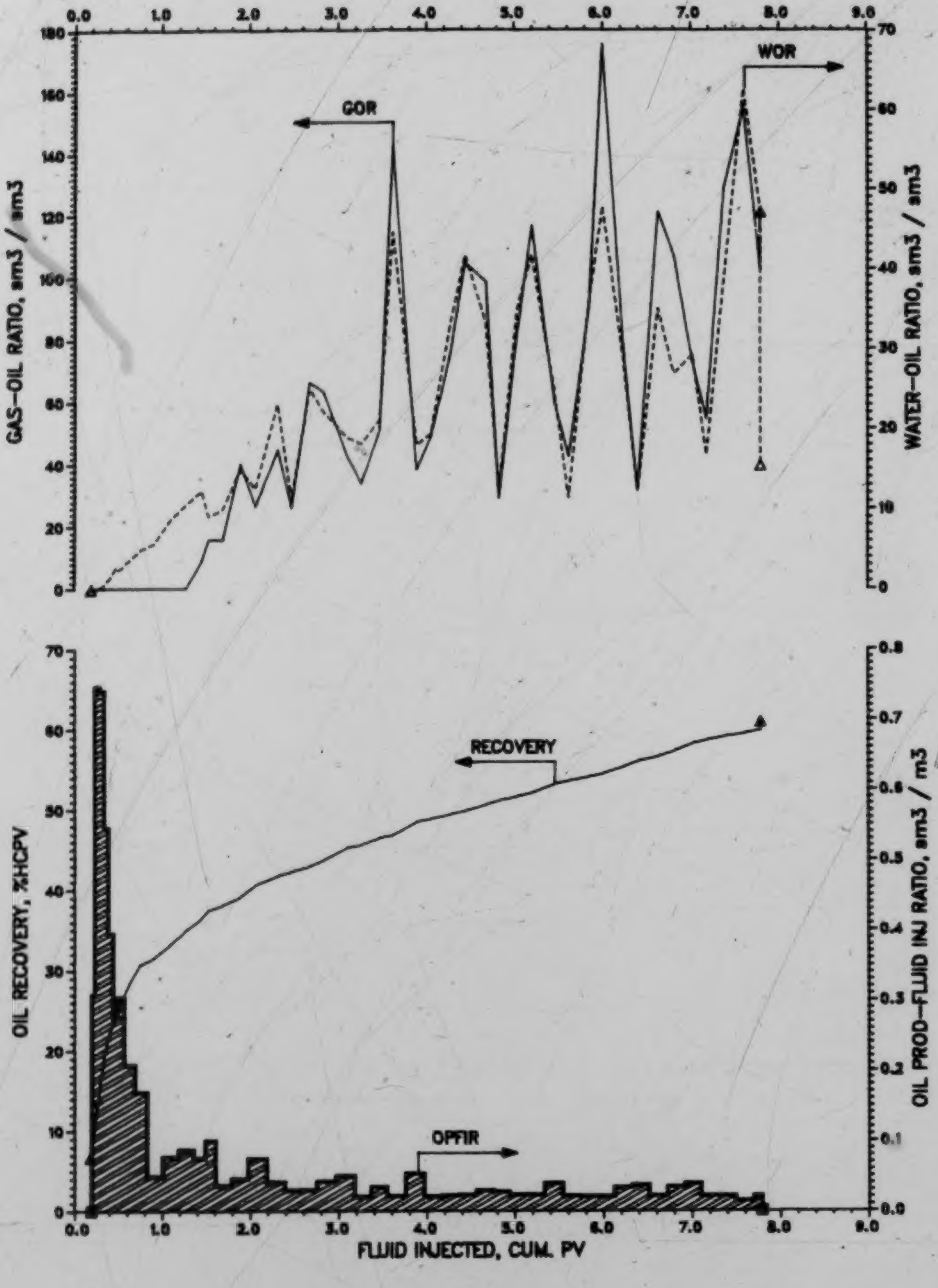
Figure C.1 Production History of Run LC 1.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.256 m/d, μ_o = 1059.0 mPa.s
ϕ = 35.00 %, k = 5.580 darcies, S_o = 90.00 %, S_{wc} = 10.00 %

[1.44 HCPV Waterflood @ 1.00 MPa]

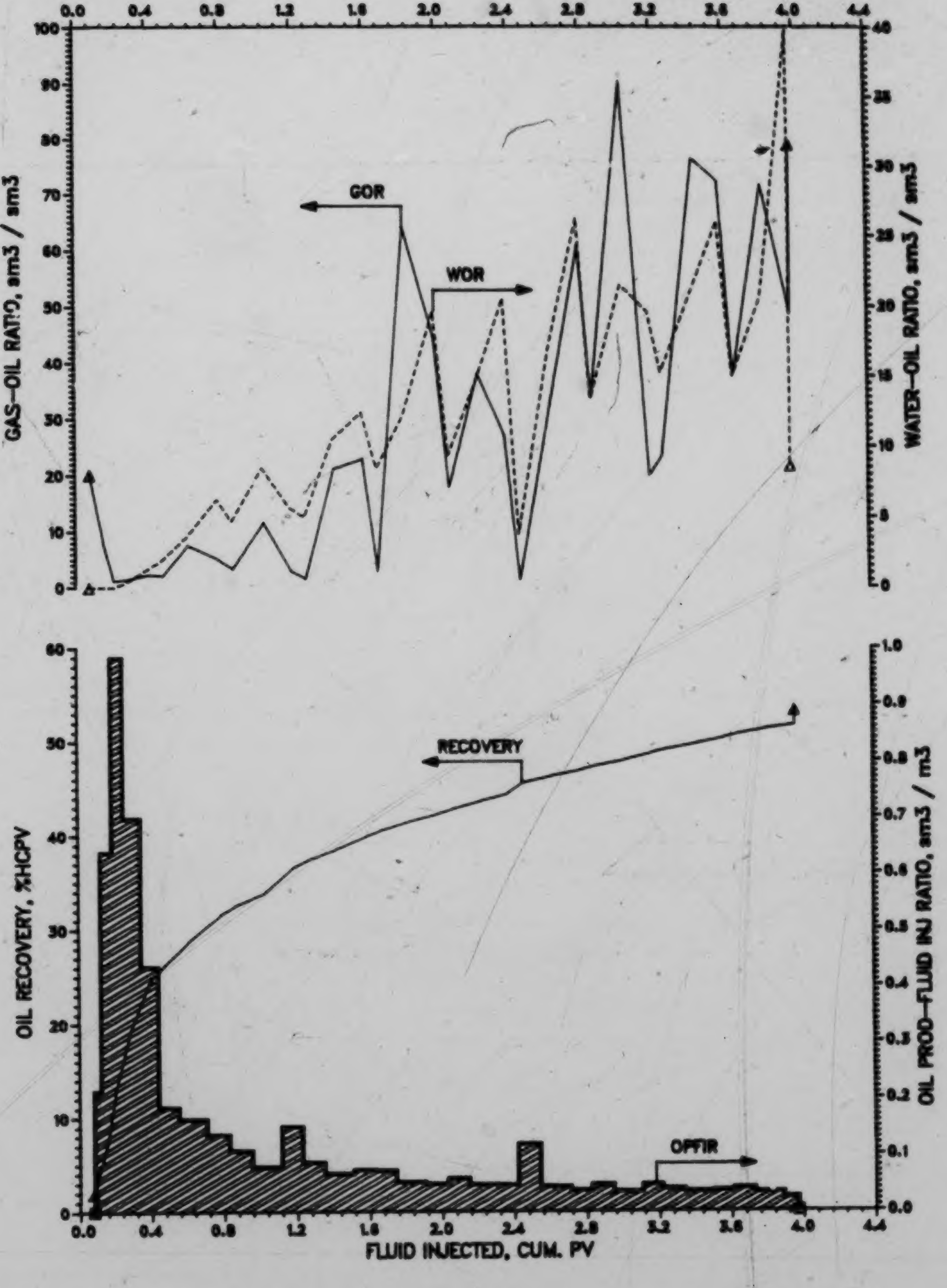
Figure C.2 Production History of Run LC 2.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 36.60 %, k = 10.657 darcies, S_o = 87.32 %, S_{wc} = 12.68 %

[1.79 HCPV CO2 @ 1.00 MPa (0.77 g-mol) 4:1 WAG, 10-Slugs]

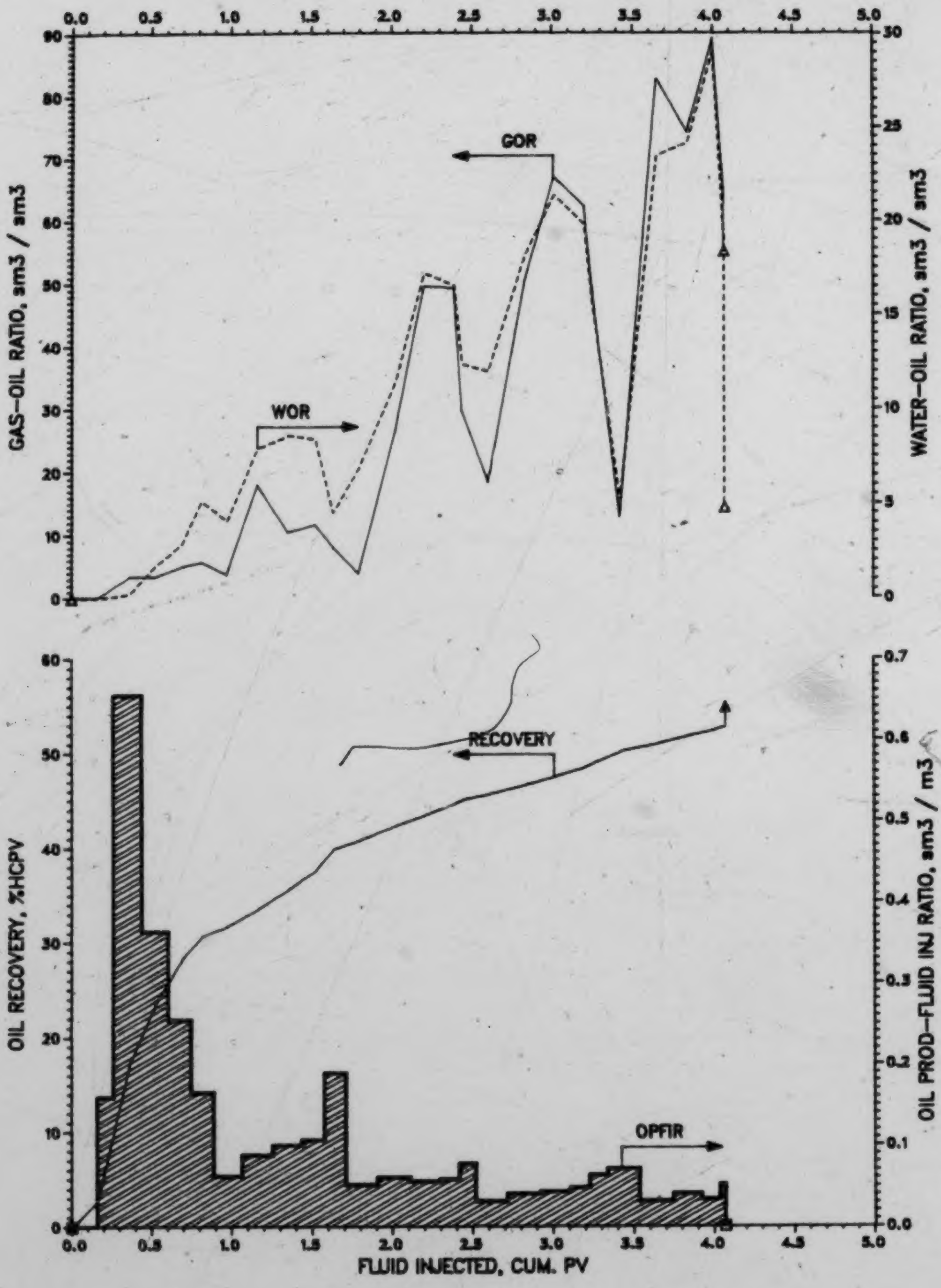
Figure C.3 Production History of Run LC3.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 36.32 %, k = 11.538 darcies, S_o = 89.26 %, S_{wc} = 10.74 %

[0.89 HCPV CO2 @ 1.00 MPa (0.39 g-mol) 4:1 WAG, 10-Slugs]

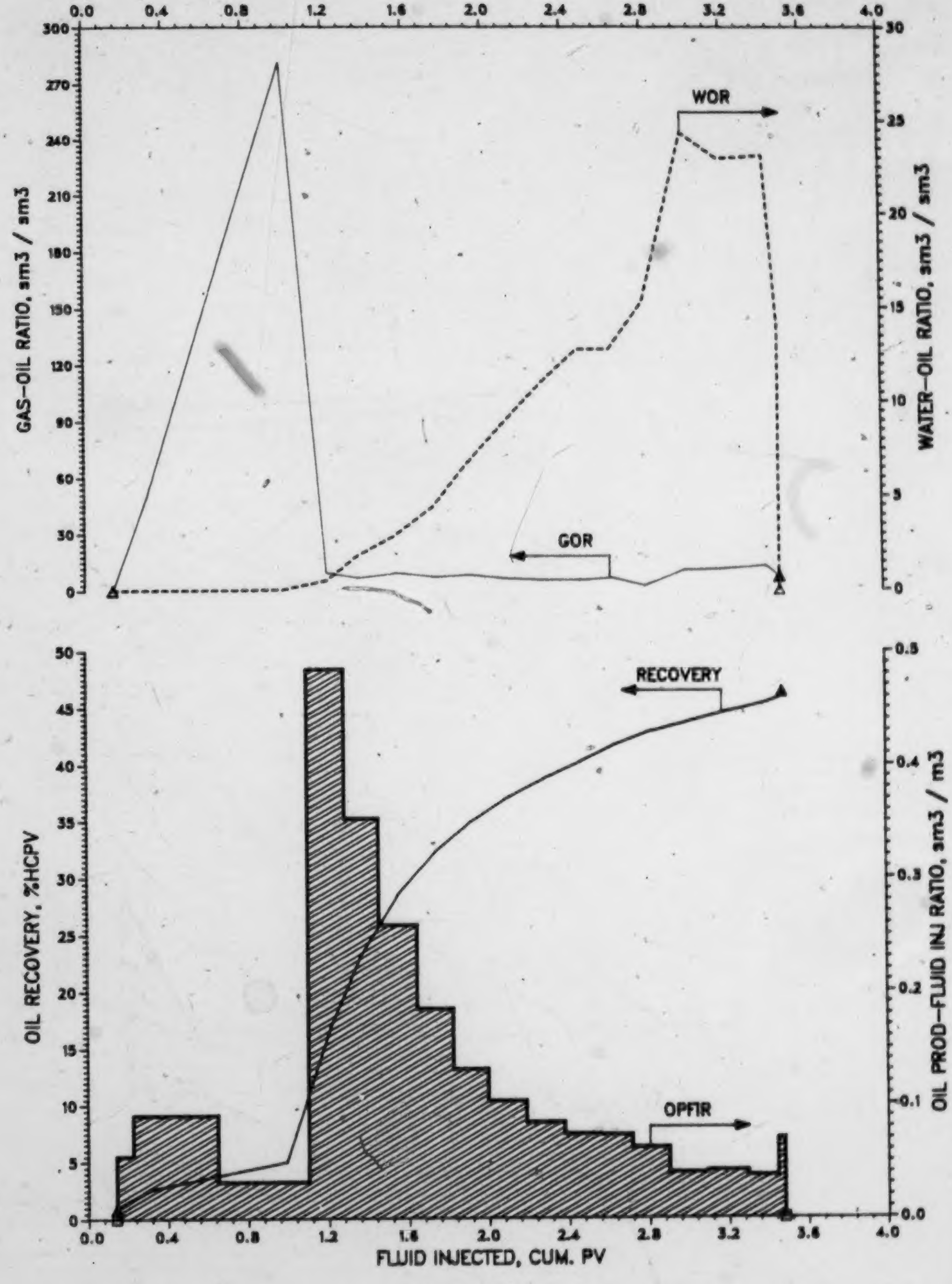
Figure C.4 Production History of Run LC4.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 35.63 %, k = 10.800 darcies, S_o = 90.10 %, S_{wc} = 9.90 %

[0.89 HCPV CO2 @ 1.00 MPa (0.39 g-mol) 4:1 WAG, 5-Slugs]

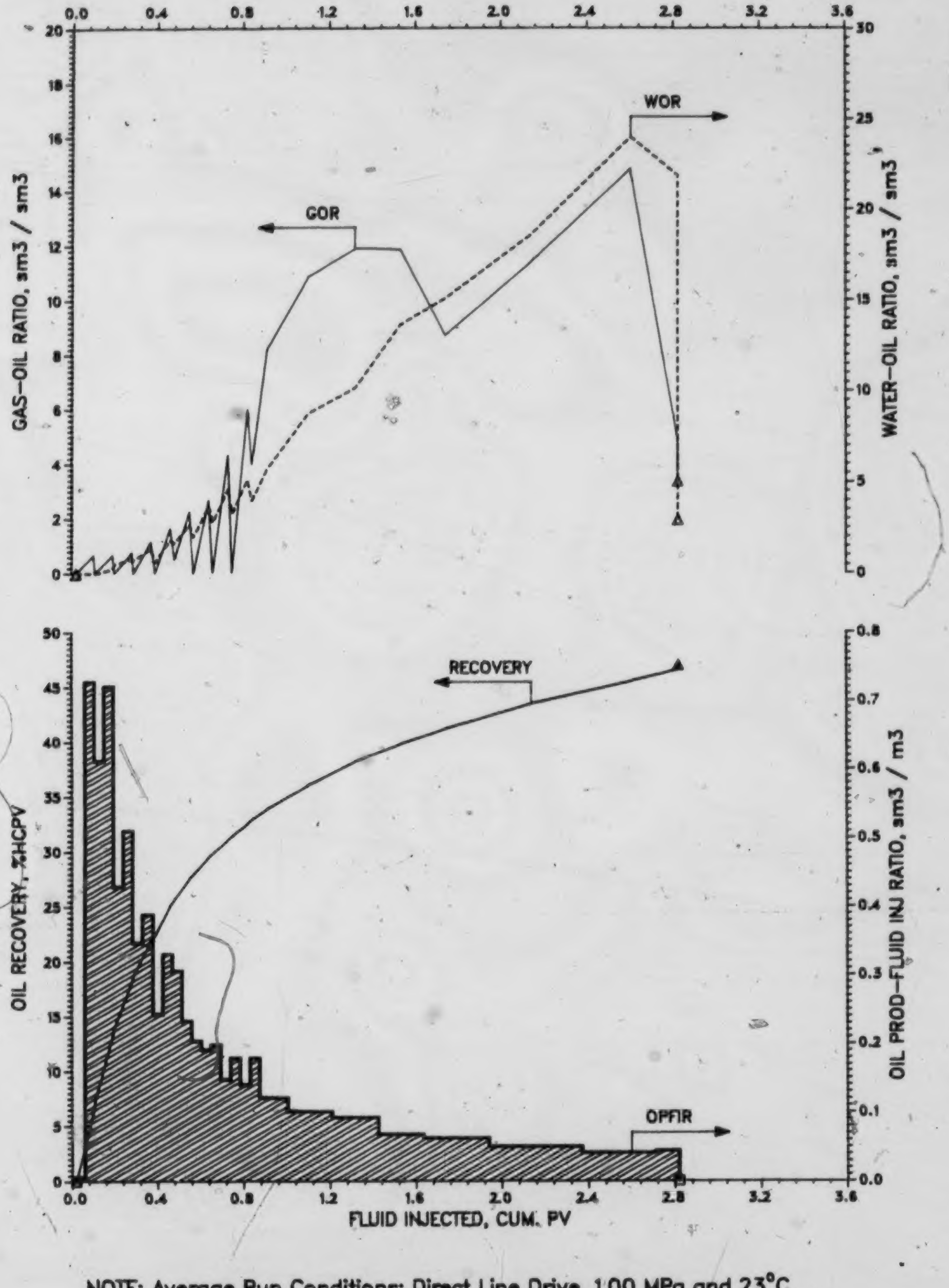
Figure C.5 Production History of Run LC5.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 34.09 %, k = 12.717 darcies, S_o = 89.24 %, S_{wc} = 10.76 %

[0.89 HCPV CO2 @ 1.00 MPa (0.39 g–mol) 4:1 WAG, 1–Slug]

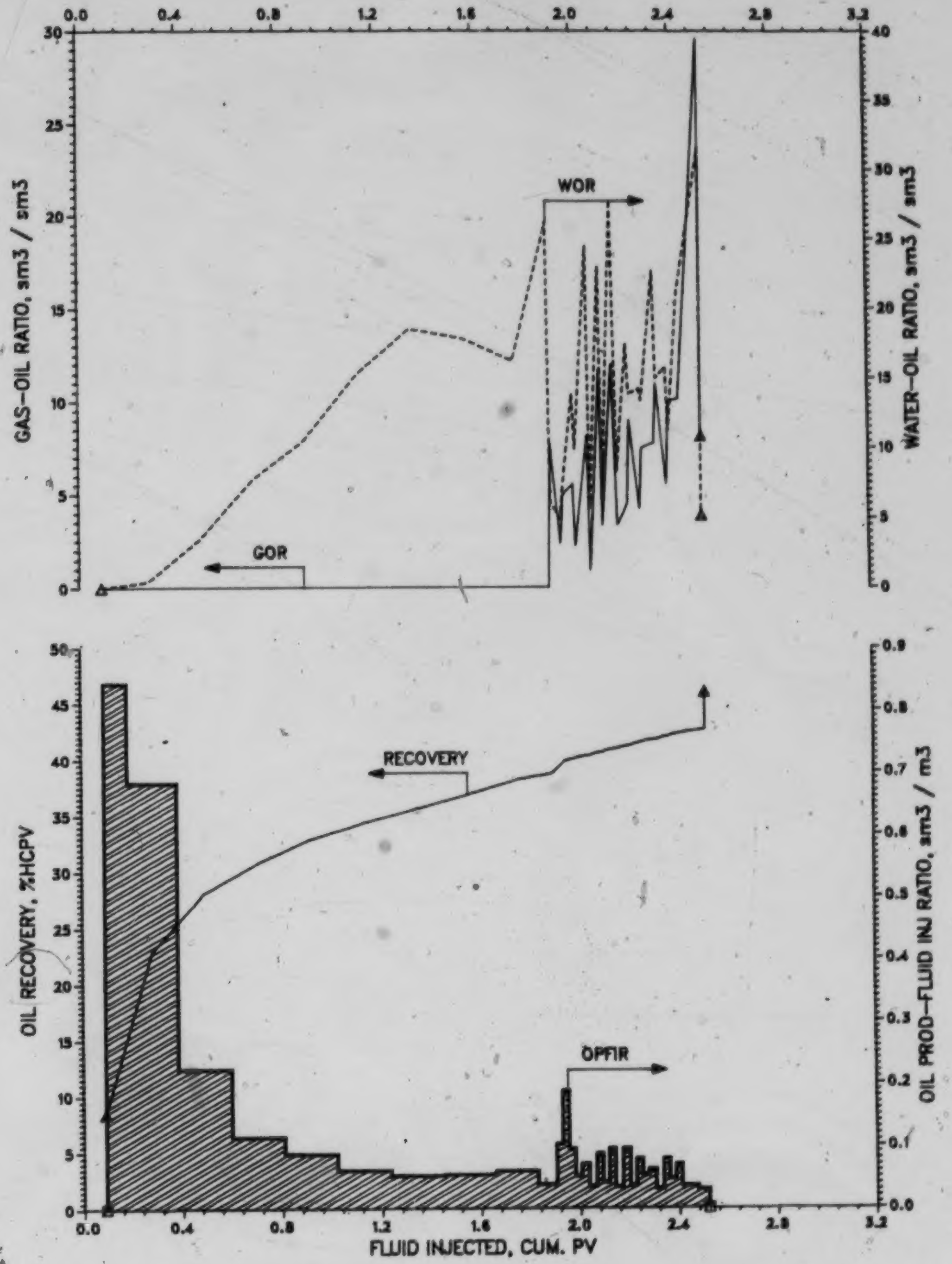
Figure C.6 Production History of Run LC6.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 34.80 %, k = 15.774 darcies, S_o = 90.58 %, S_{wc} = 9.42 %

[0.20 HCPV CO2 @ 1.00 MPa (0.08 g-mol) 4:1 WAG, 10-Slugs]

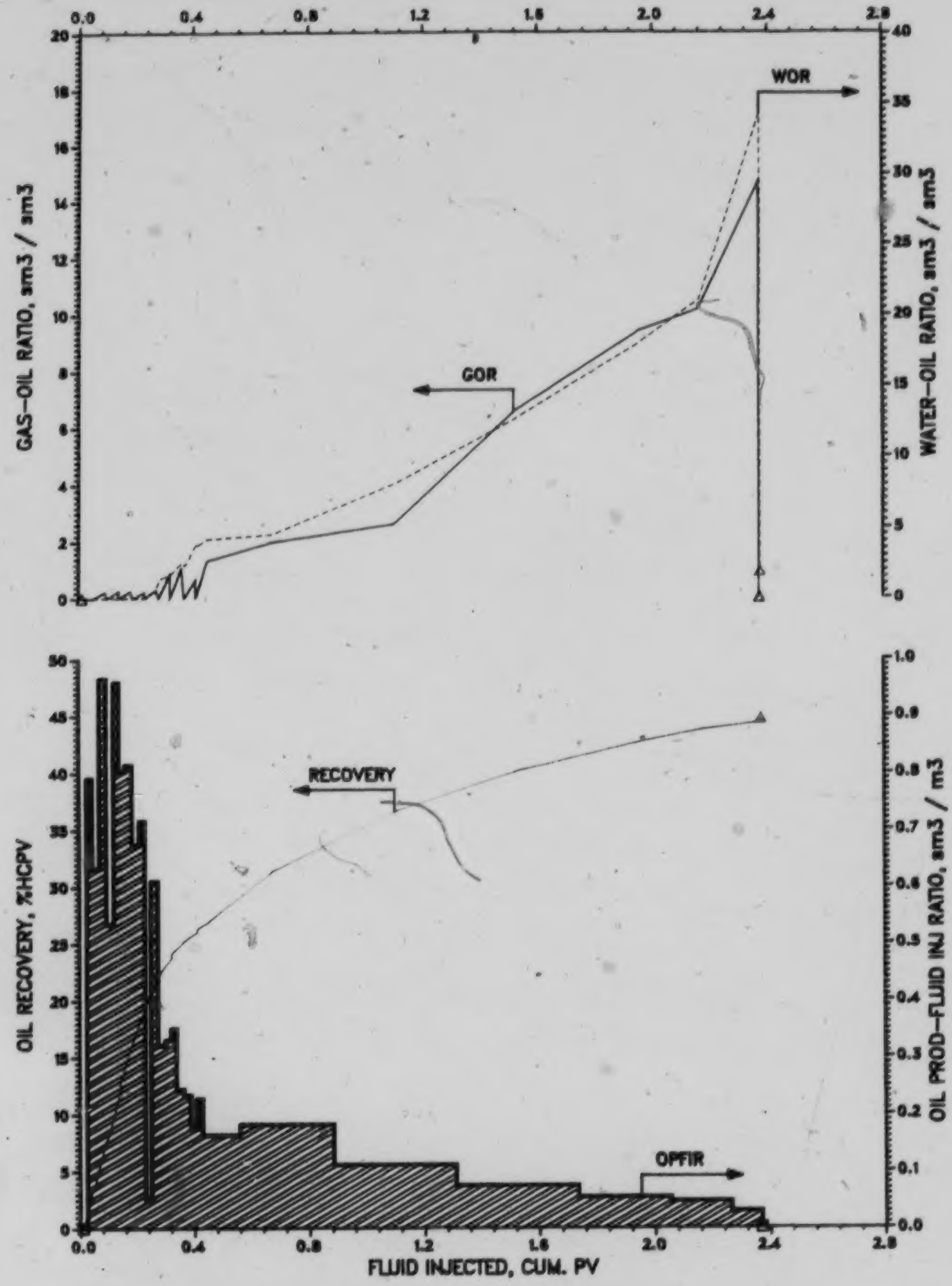
Figure C.7 Production History of Run LC7.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 37.05 %, k = 11.379 darcies, S_o = 89.69 %, S_{wc} = 10.31 %

[2.11 HCPV WF ⇒ 0.20 RHCPV CO2 @ 1.00 MPa (0.05 g–mol) 4:1 WAG]

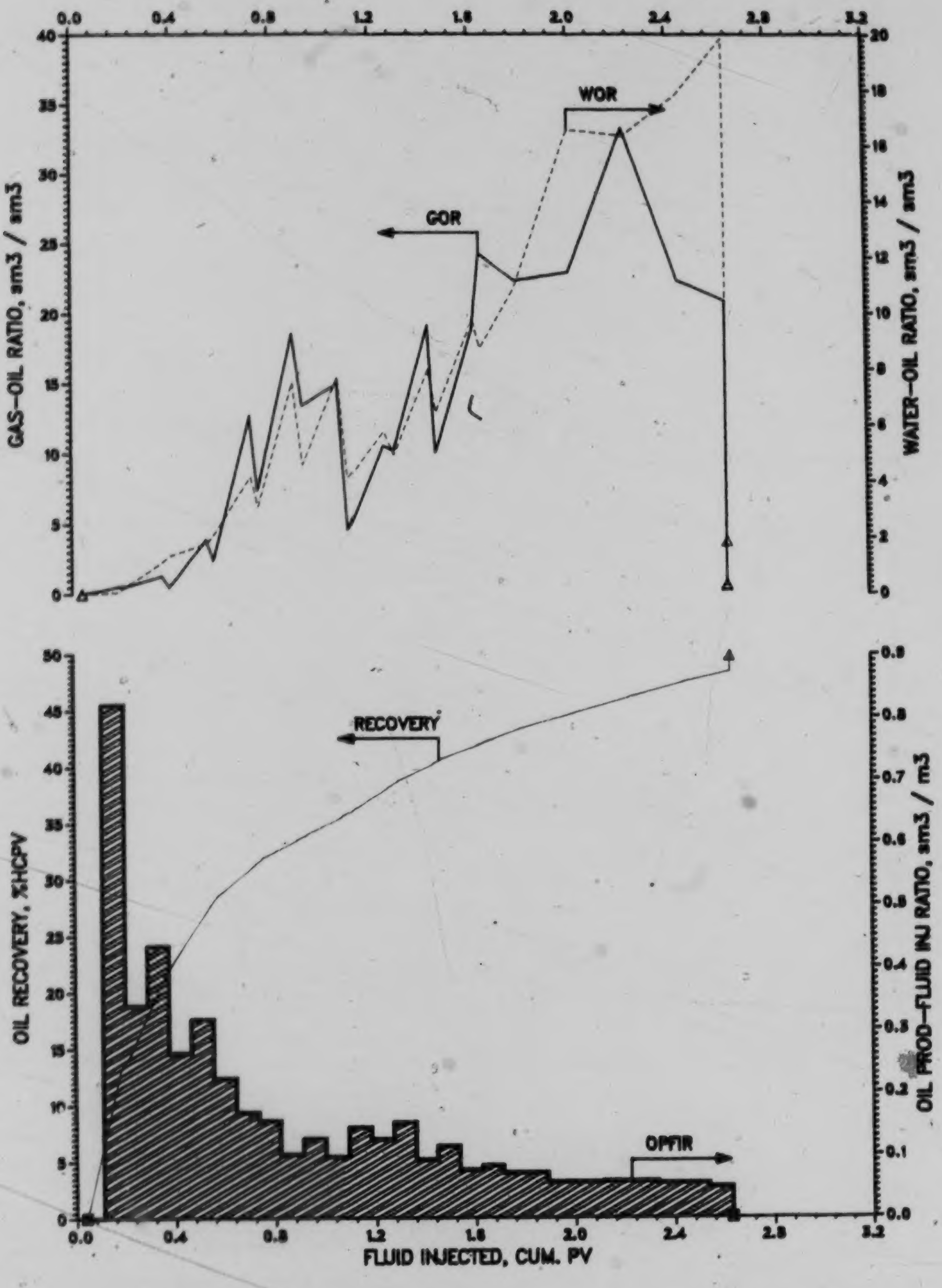
Figure C.8 Production History of Run LC8(a,b).



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 36.73 %, k = 12.667 darcies, S_o = 90.04 %, S_{wc} = 9.96 %

[0.10 HCPV CO2 @ 1.00 MPa (0.04 g-mol) 4:1 WAG, 10-Slugs]

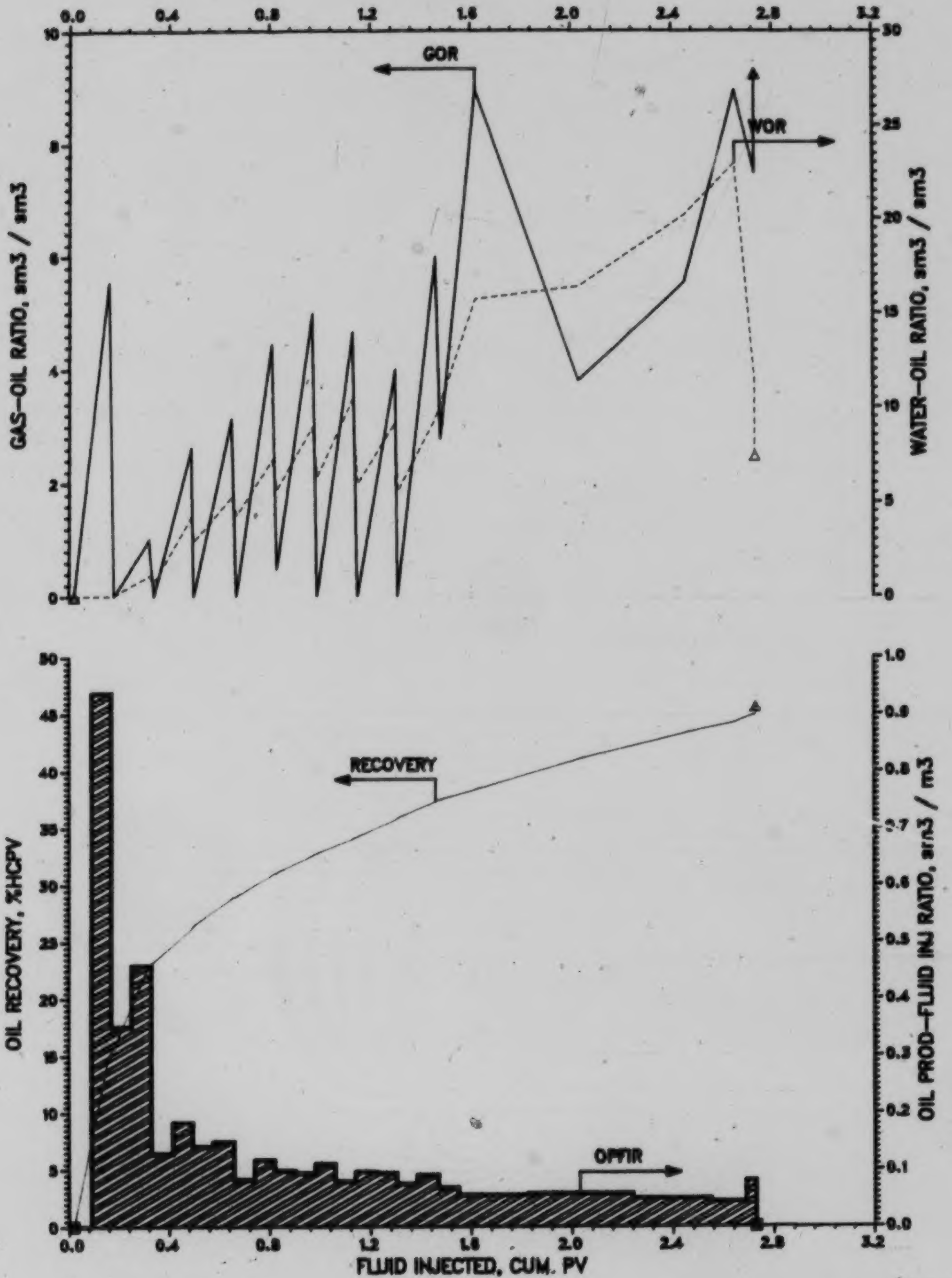
Figure C.9 Production History of Run LC9.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 35.77 %, k = 10.978 darcies, S_o = 88.93 %, S_{wc} = 11.07 %

[0.40 HCPV CO2 @ 1.00 MPa (0.17 g-mol) 4:1 WAG, 10-Slugs]

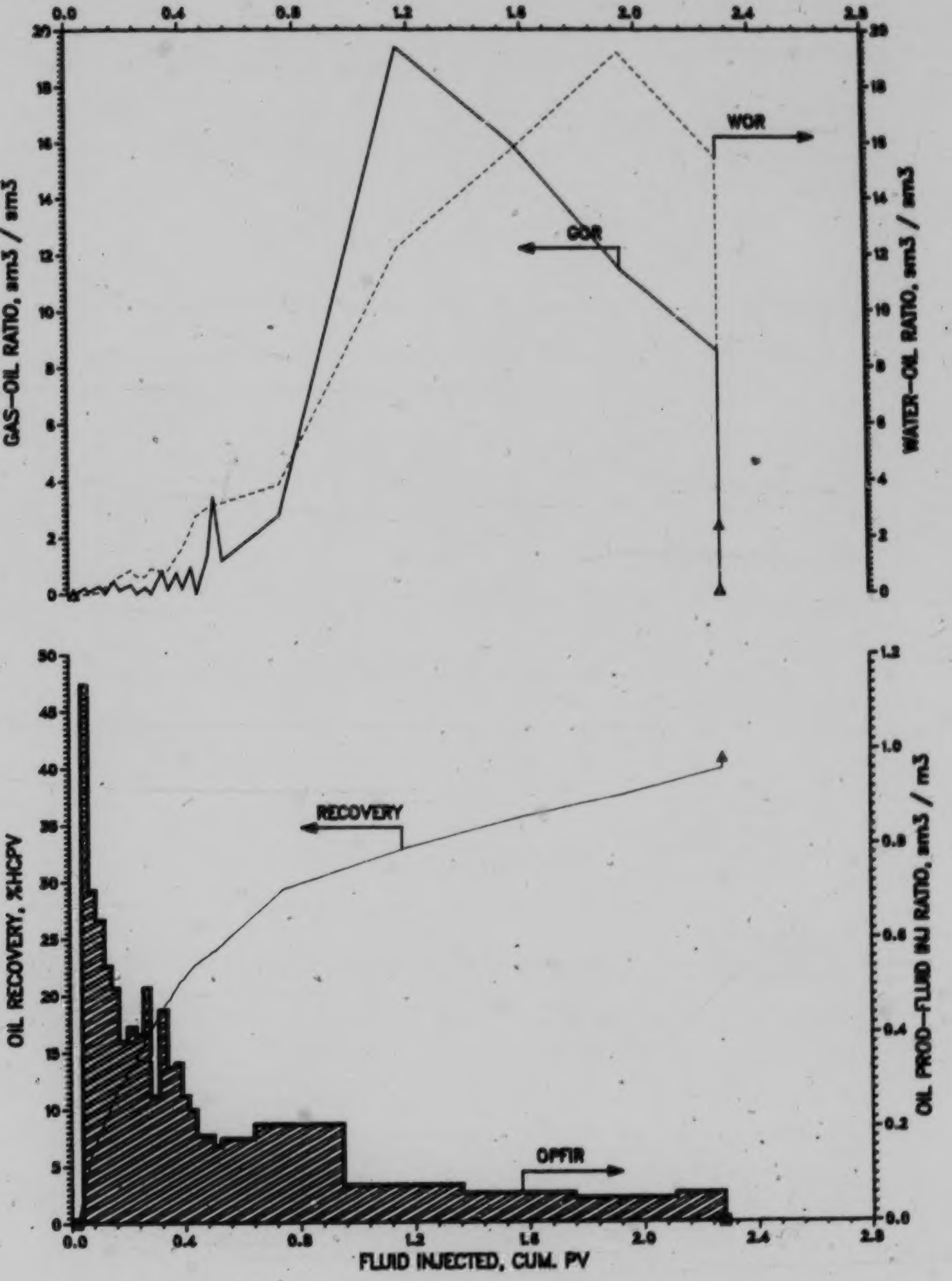
Figure C.10 Production History of Run LC10.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 38.28 %, k = 13.998 darcies, S_o = 89.95 %, S_{wc} = 10.05 %

[0.20 HCPV CO2 @ 1.00 MPa (0.09 g-mol) 8:1 WAG, 10-Slugs]

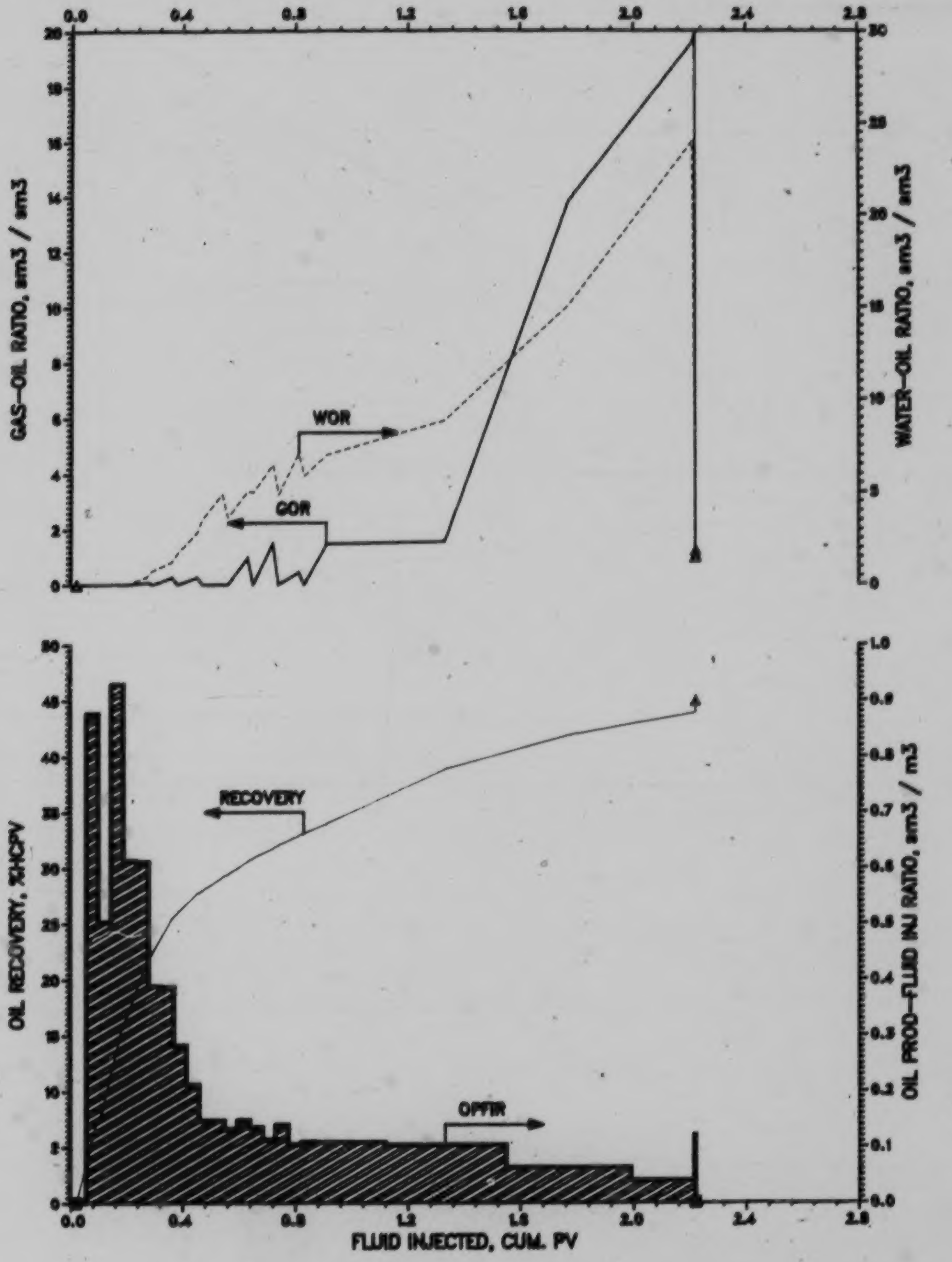
Figure C.11 Production History of Run LC11.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 38.40 %, k = 16.156 darcies, S_o = 90.84 %, S_{wc} = 9.16 %

[0.20 HCPV CO2 @ 1.00 MPa (0.09 g-mol) 2:1 WAG, 10-Slugs]

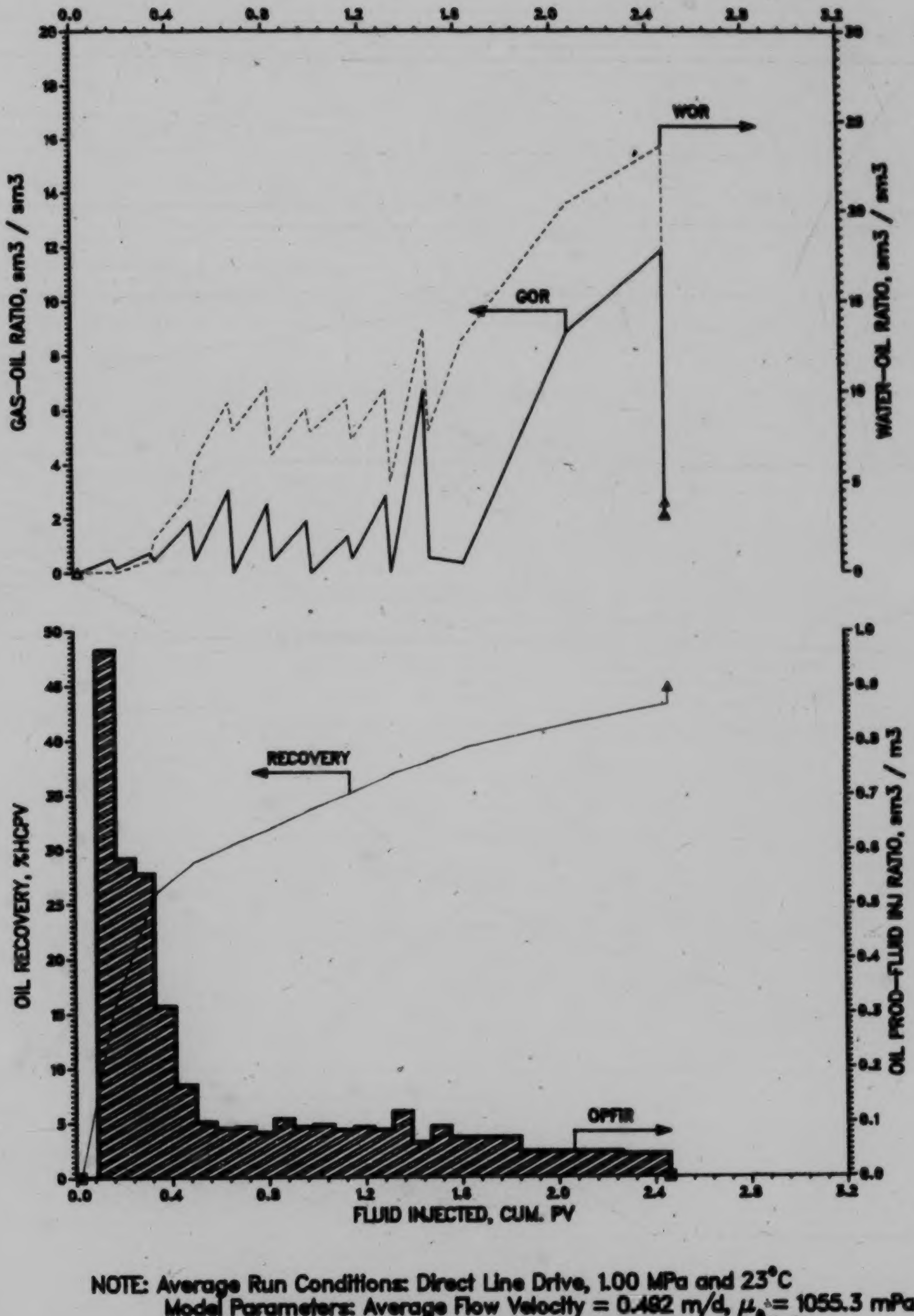
Figure C.12 Production History of Run LC12.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.492 m/d, μ_o = 1055.3 mPa.s
ϕ = 36.22 %, k = 12.118 darcies, S_o = 90.51 %, S_{wc} = 9.49 %

[0.20 HCPV CO2 @ 1.00 MPa (0.09 g—mol) 4:1 WAG, 10—Slugs]

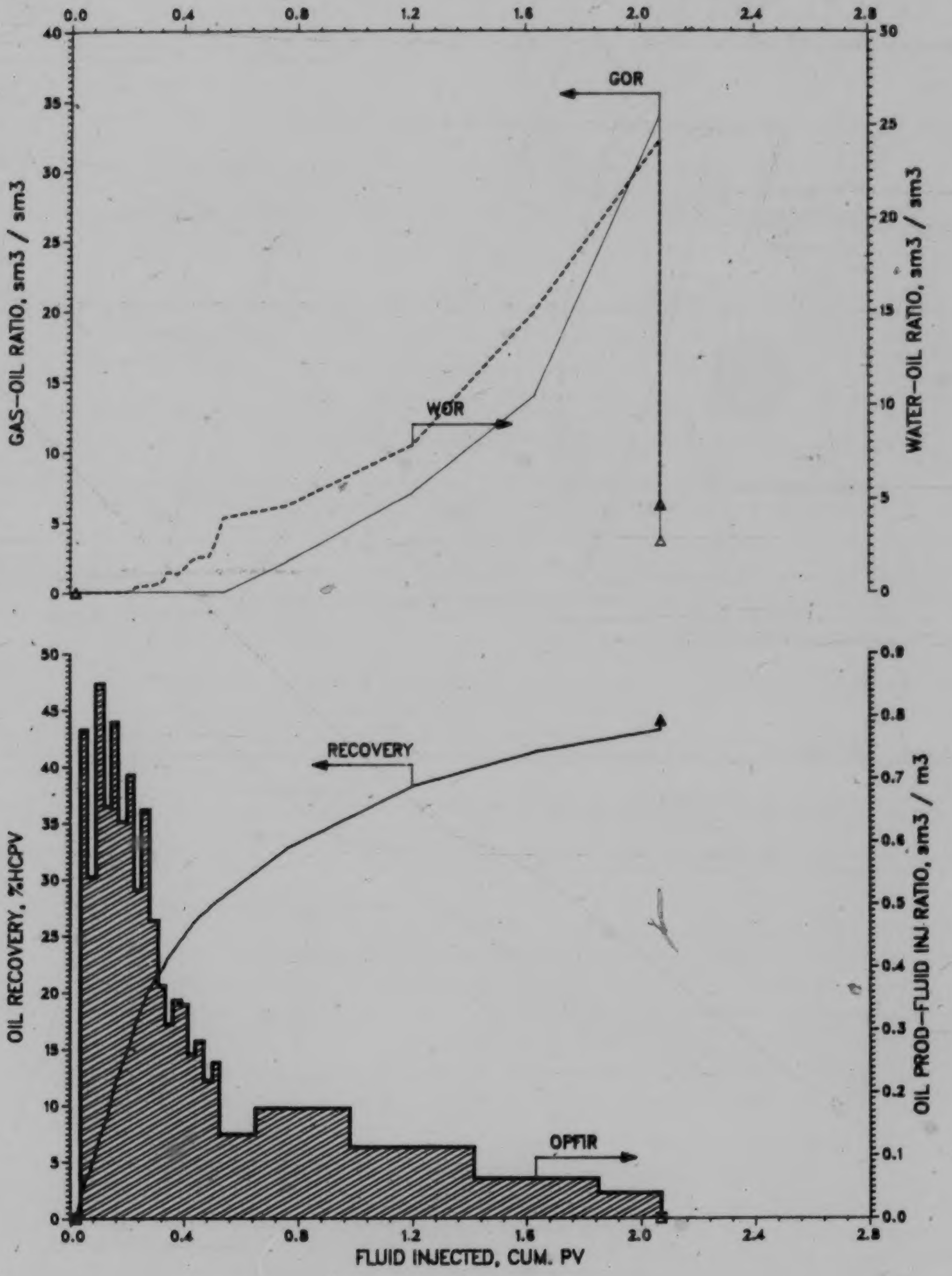
Figure C.13 Production History of Run LC13.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.482 m/d, μ_o = 1055.3 mPa.s
ϕ = 36.93 %, k = 12.047 darcies, S_o = 90.22 %, S_{wc} = 9.78 %

[0.20 HCPV CO2 @ 1.00 MPa (0.09 g-mol) 8:1 WAG, 10-Slugs]

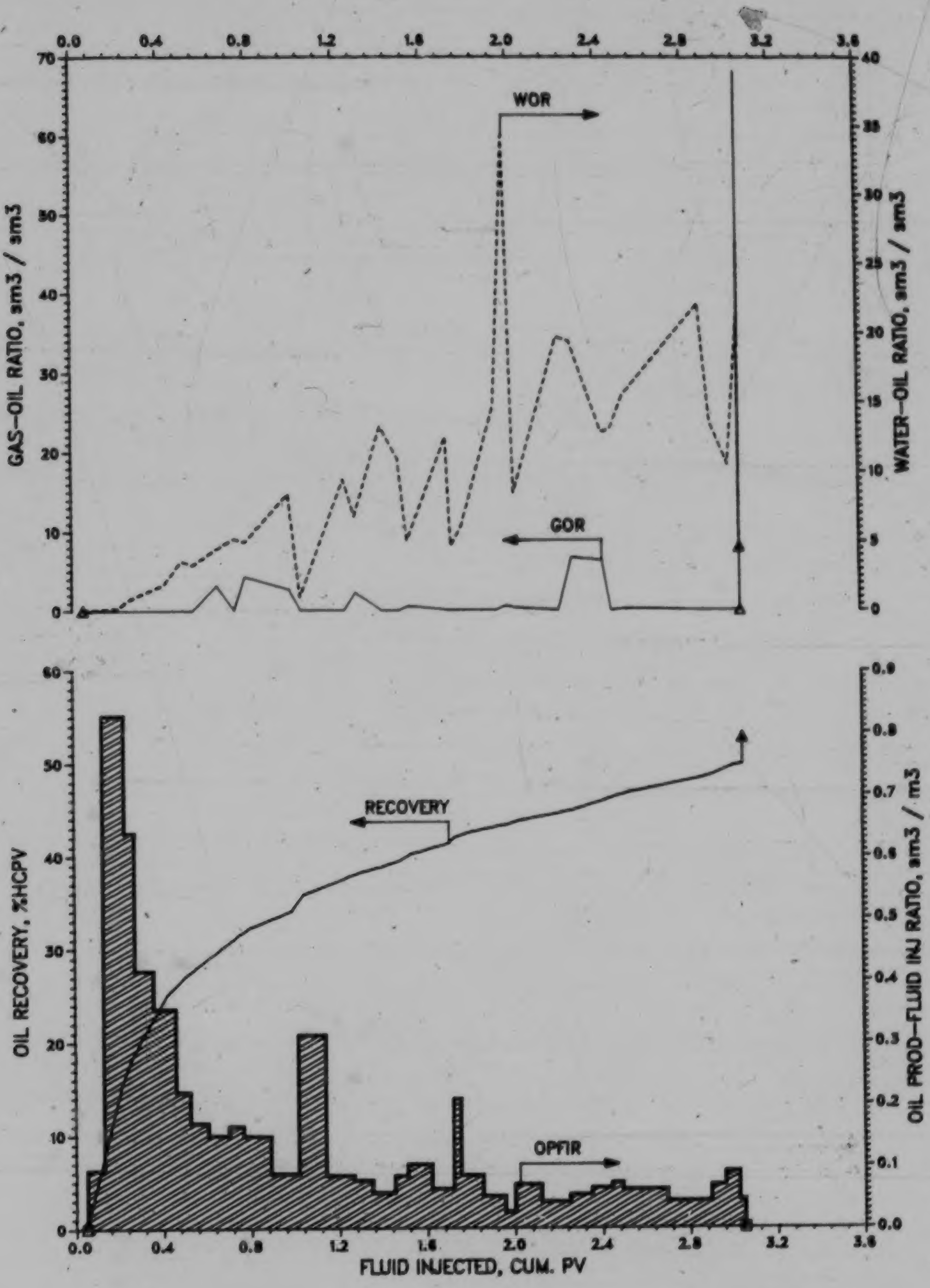
Figure C.14 Production History of Run LC14.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.492 m/d, μ_o = 1055.3 mPa.s
ϕ = 36.57 %, k = 12.056 darcies, S_o = 90.28 %, S_{wc} = 9.72 %

[0.20 HCPV CO2 @ 1.00 MPa (0.09 g-mol) 2:1 WAG, 10-Slugs]

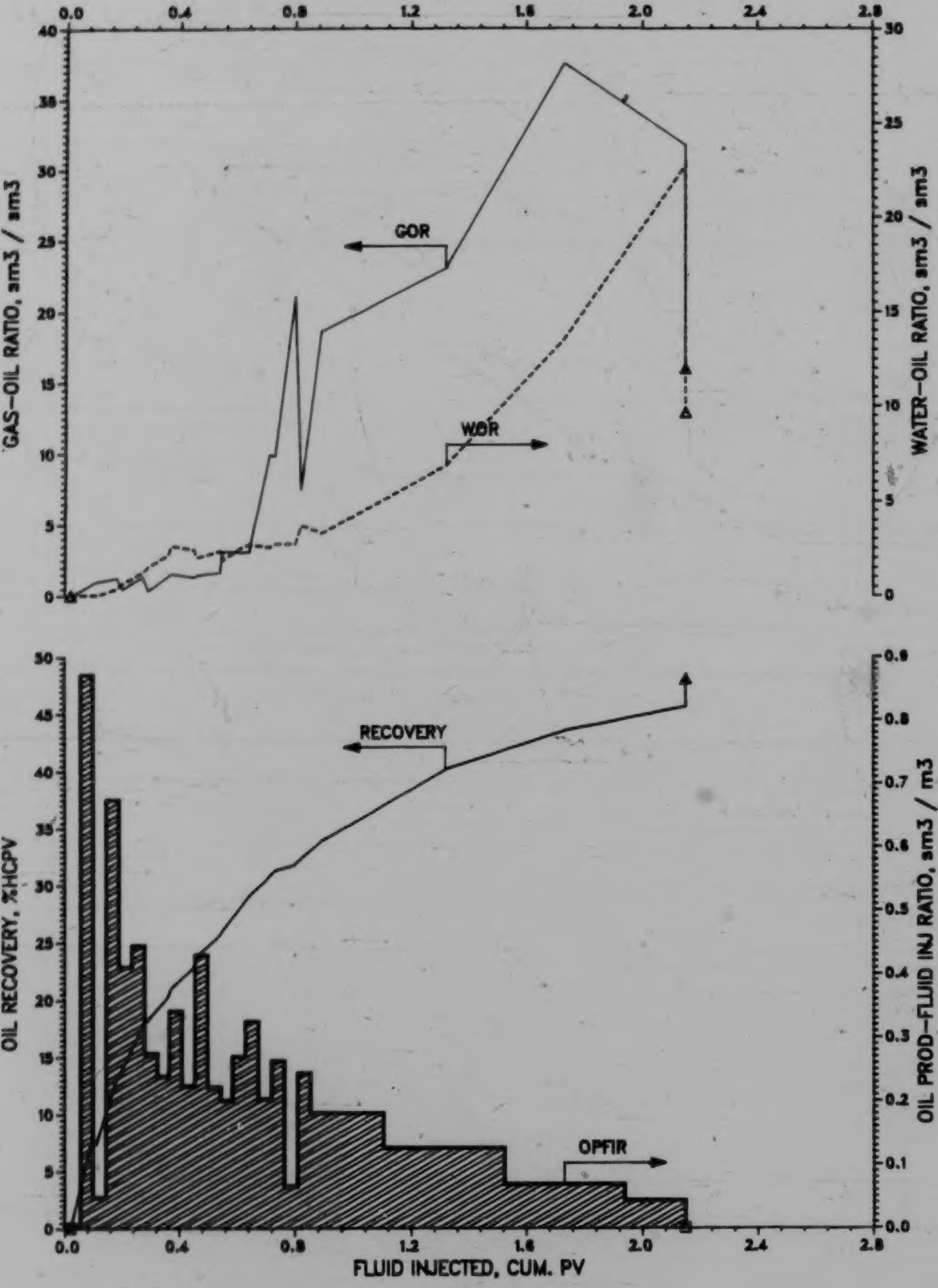
Figure C. 15 Production History of Run LC15.



NOTE: Average Run Conditions: Direct Line Drive, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1059.0 mPa.s
ϕ = 34.77 %, k = 9.025 darcies, S_o = 79.11 %, S_{wc} = 20.89 %

[0.64 HCPV CO2 @ 2.50 MPa (0.75 g–mol) 4:1 WAG, 10–Slugs]

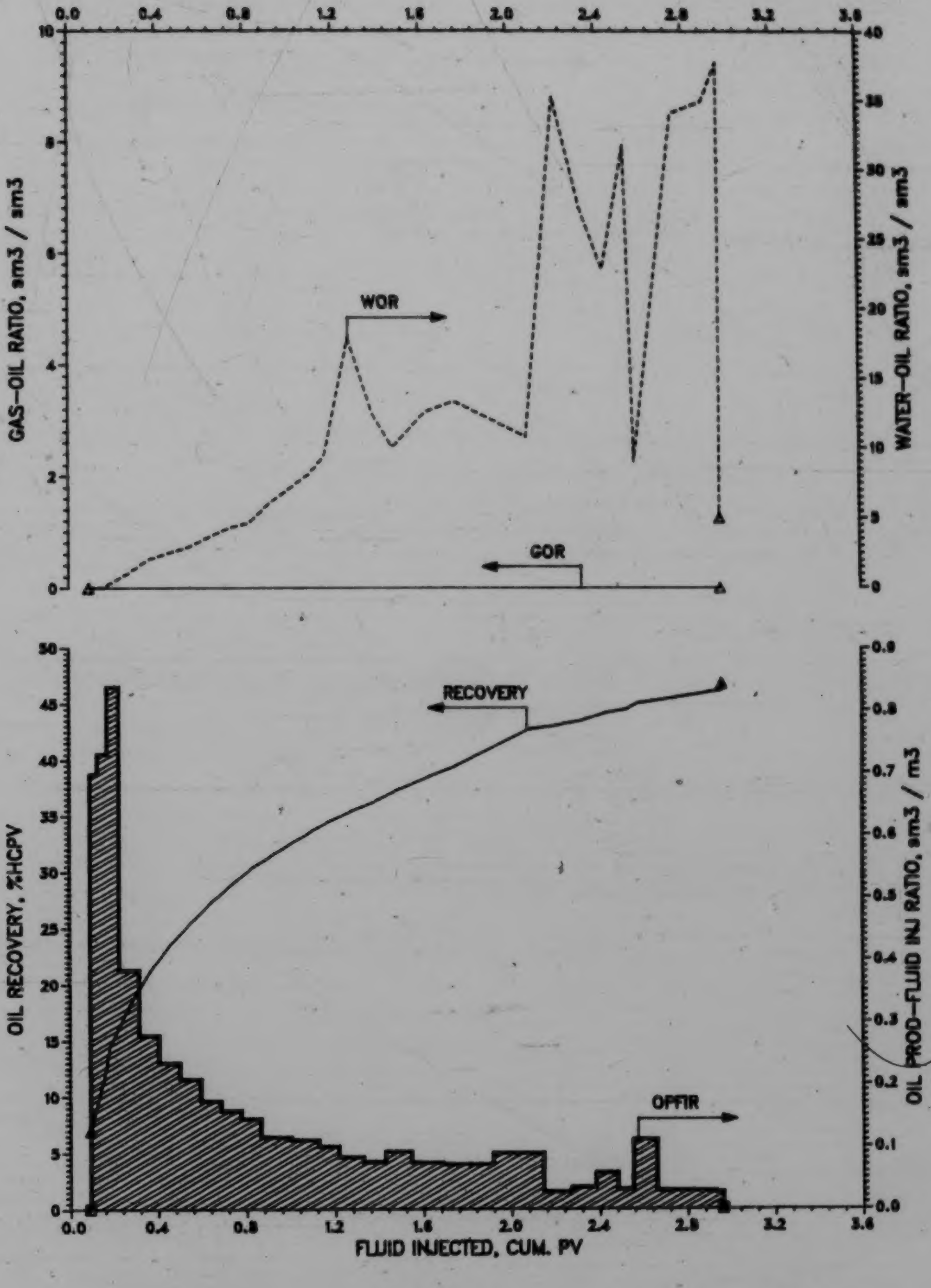
Figure C.16 Production History of Run LC16.



NOTE: Average Run Conditions: Direct Line Drive, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 37.70 %, k = 12.304 darcies, S_o = 89.16 %, S_{wc} = 10.84 %

[0.20 HCPV CO2 @ 2.50 MPa (0.26 g–mol) 4:1 WAG, 10–Slugs]

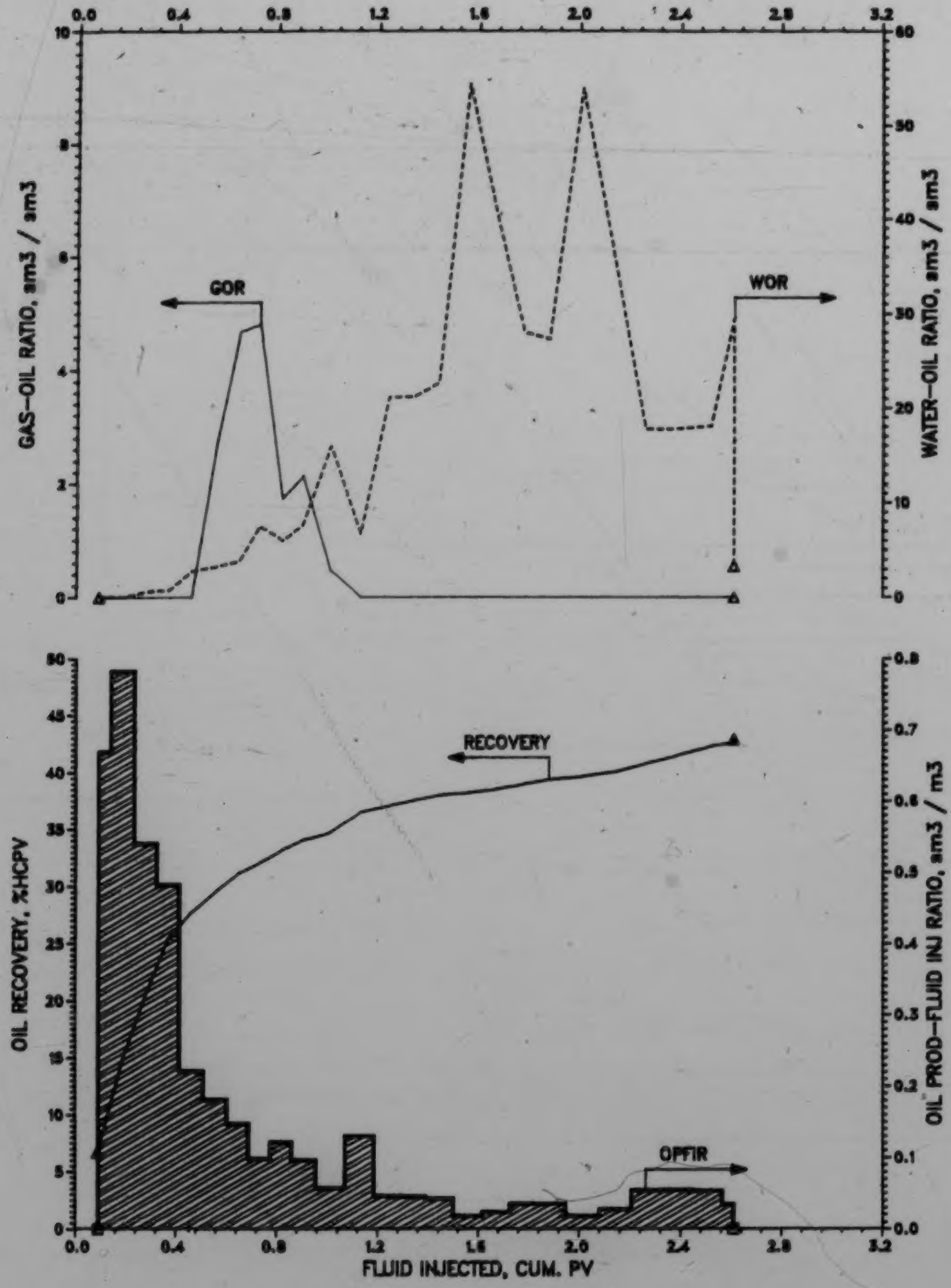
Figure C.17 Production History of Run LC17.



NOTE: Average Run Conditions: Direct Line Drive, 5.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1059.0 mPa.s
ϕ = 33.31 %, k = 5.912 darcies, S_o = 89.72 %, S_{wc} = 10.28 %

[0.21 HCPV CO2 @ 5.50 MPa (0.74 g-mol) 4:1 WAG, 10-Slugs]

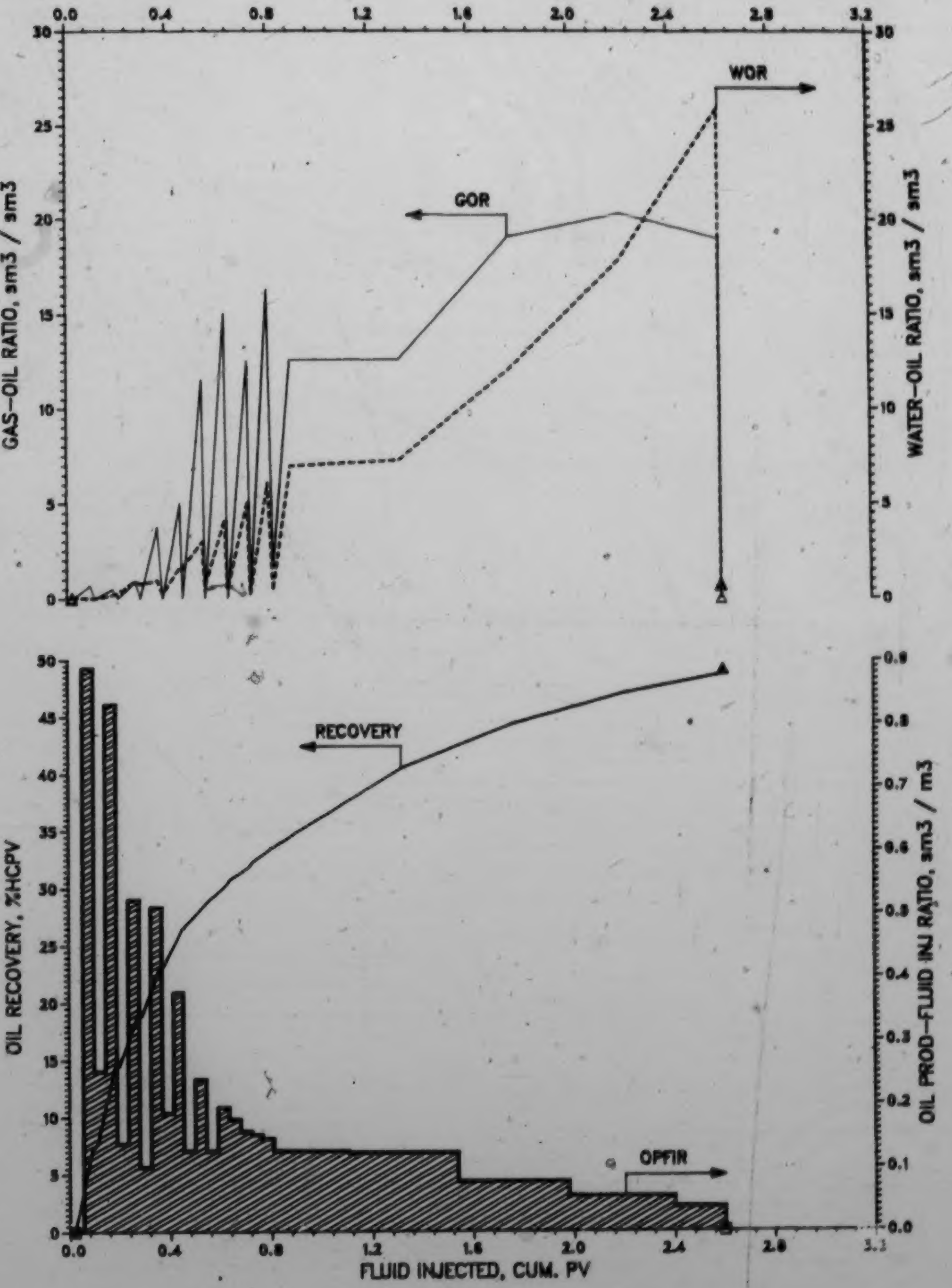
Figure C. 18 Production History of Run LC18.



NOTE: Average Run Conditions: Direct Line Drive, 5.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1059.0 mPa.s
ϕ = 34.41 %, k = 12.363 darcies, S_o = 89.22 %, S_{wc} = 10.78 %

[0.20 HCPV CO2 @ 5.50 MPa (0.70 g-mol) 4:1 WAG, 10-Slugs]

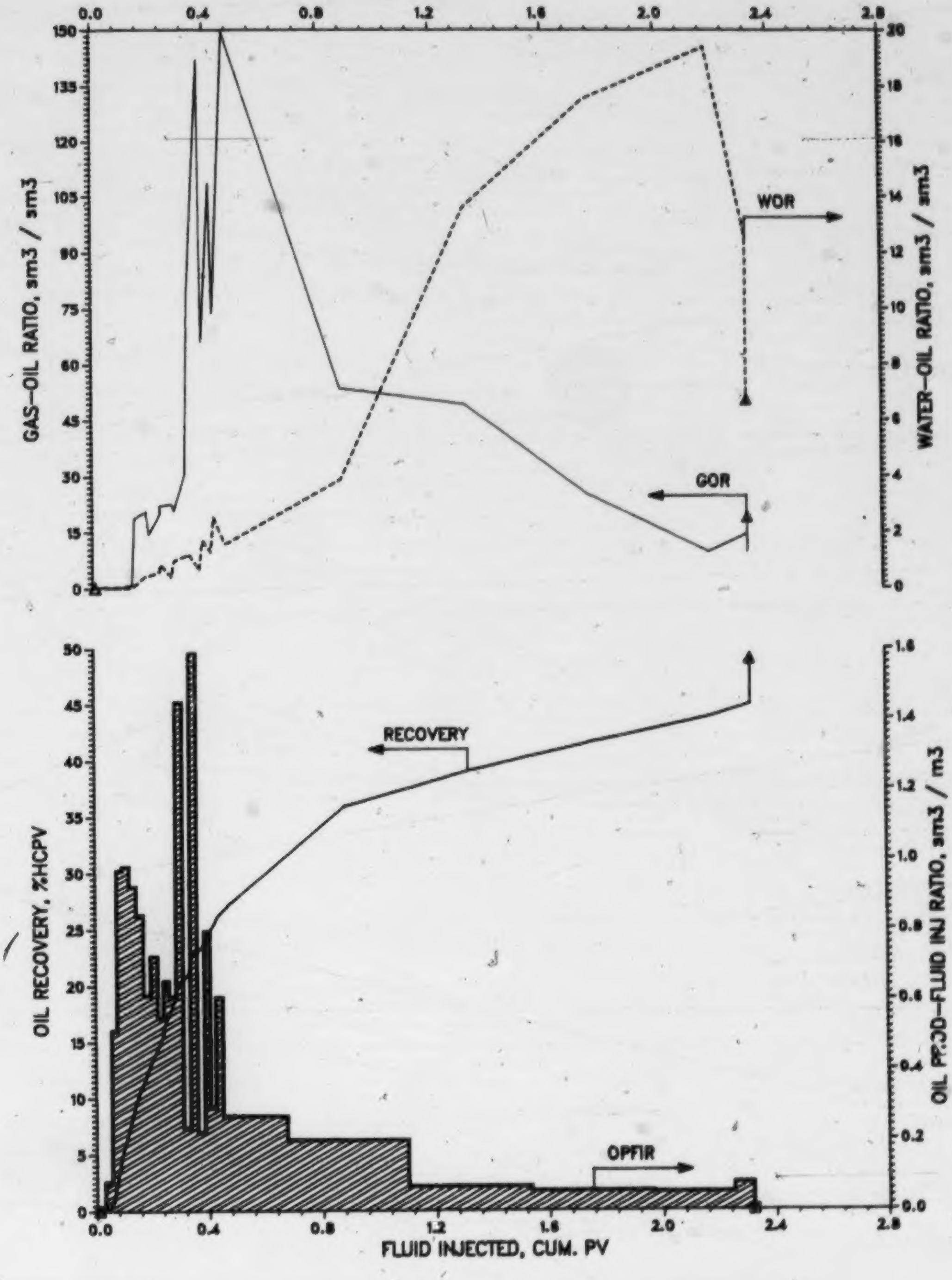
Figure C.19 Production History of Run LC19.



NOTE: Average Run Conditions: Direct Line Drive, 5.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 35.77 %, k = 12.451 darcies, S_o = 89.34 %, S_{wc} = 10.66 %

[0.20 HCPV CO2 @ 5.50 MPa (0.78 g–mol) 4:1 WAG, 10–Slugs]

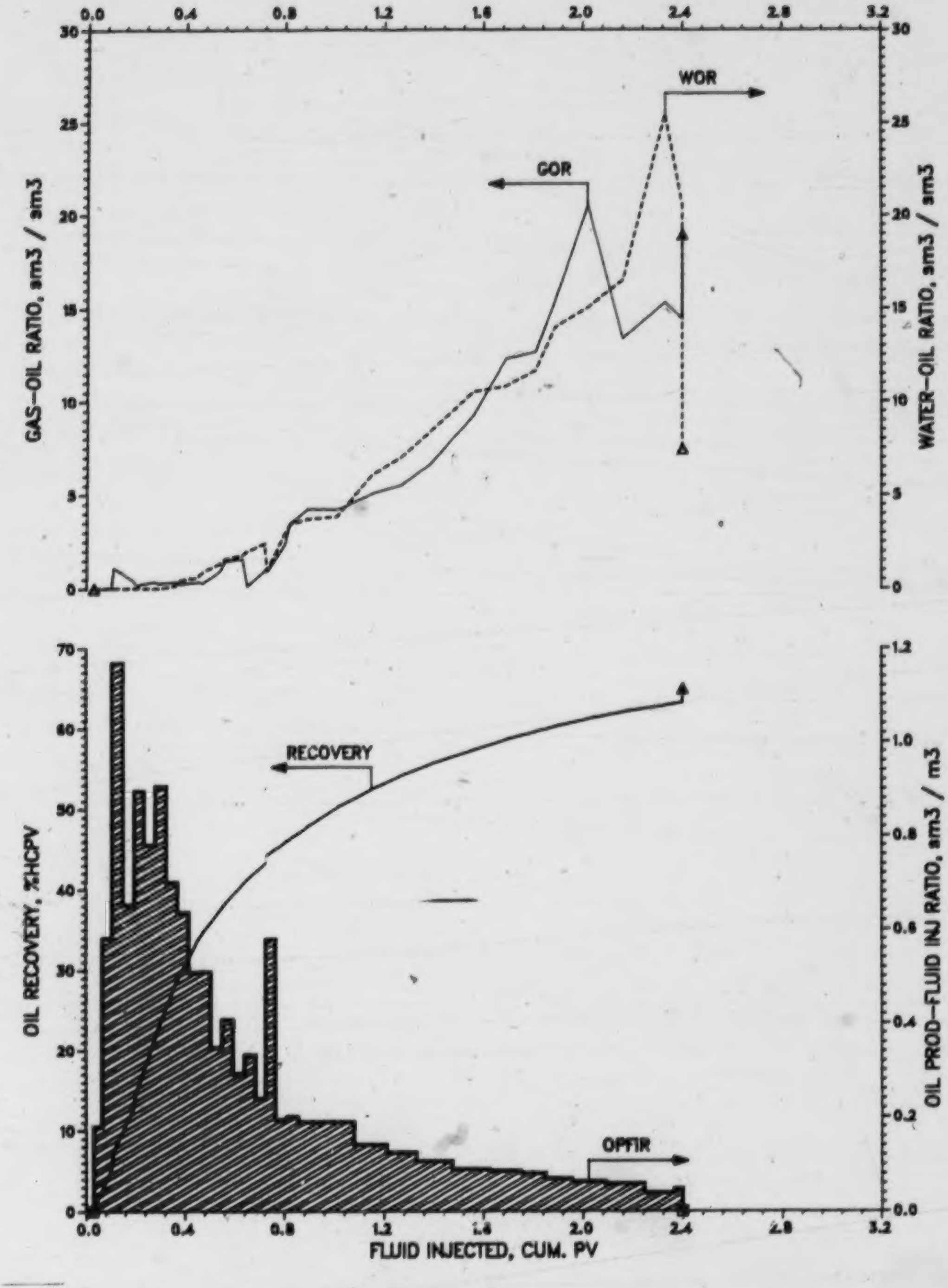
Figure C.20 Production History of Run LC20.



NOTE: Average Run Conditions: Direct Line Drive, 5.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 36.69 %, k = 15.095 darcies, S_o = 93.95 %, S_{wc} = 6.05 %

[0.10 HCPV CO2 @ 5.50 MPa (0.42 g–mol) 4:1 WAG, 10–Slugs]

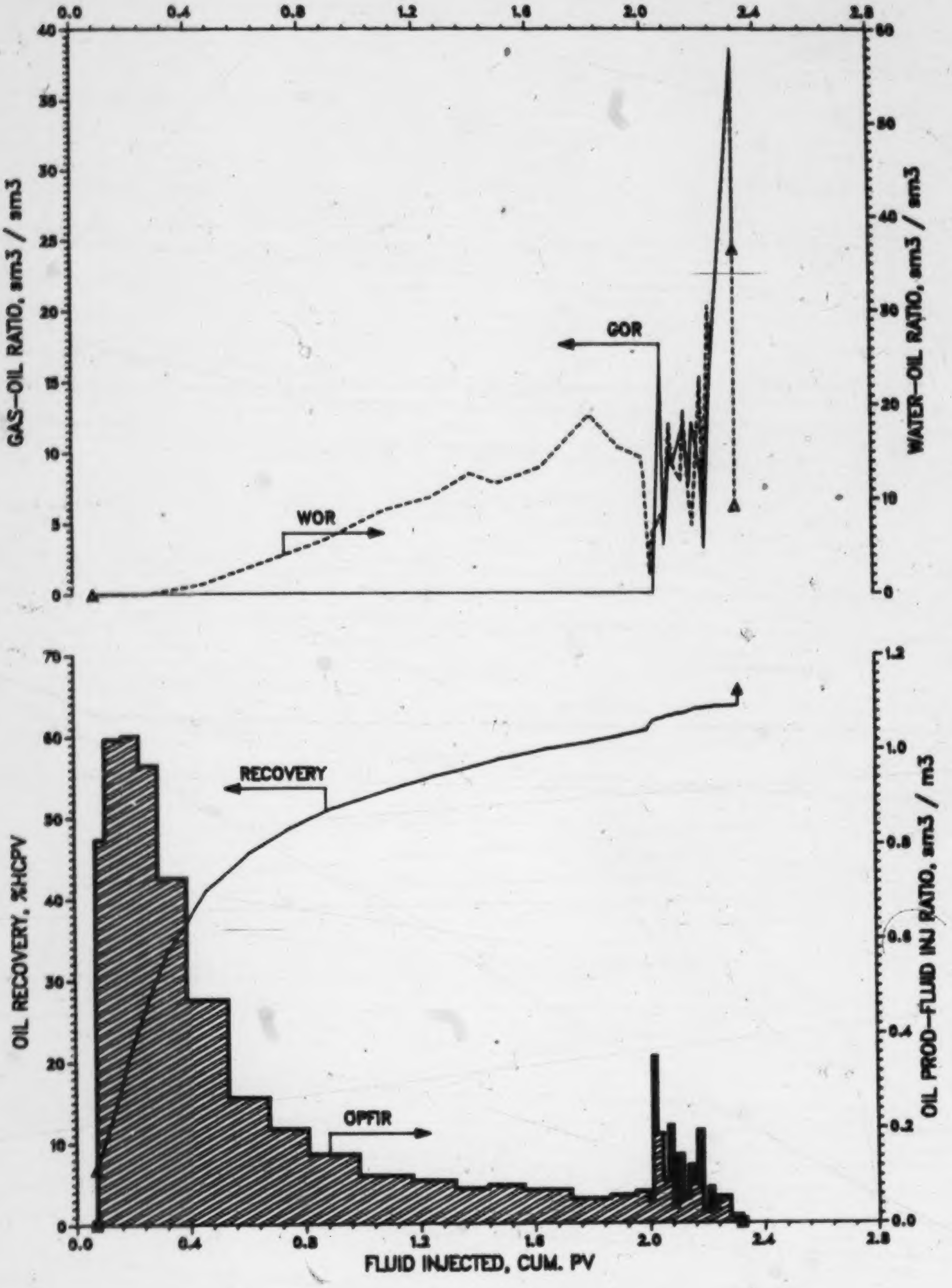
Figure C. 21 Production History of Run LC21.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 150.0 mPa.s
ϕ = 36.67 %, k = 11.414 darcies, S_o = 88.20 %, S_{wc} = 11.80 %

[0.20 HCPV C02 @ 1.00MPa (0.09 g-mol) 4:1 WAG, 10-Slugs, Wainwright]

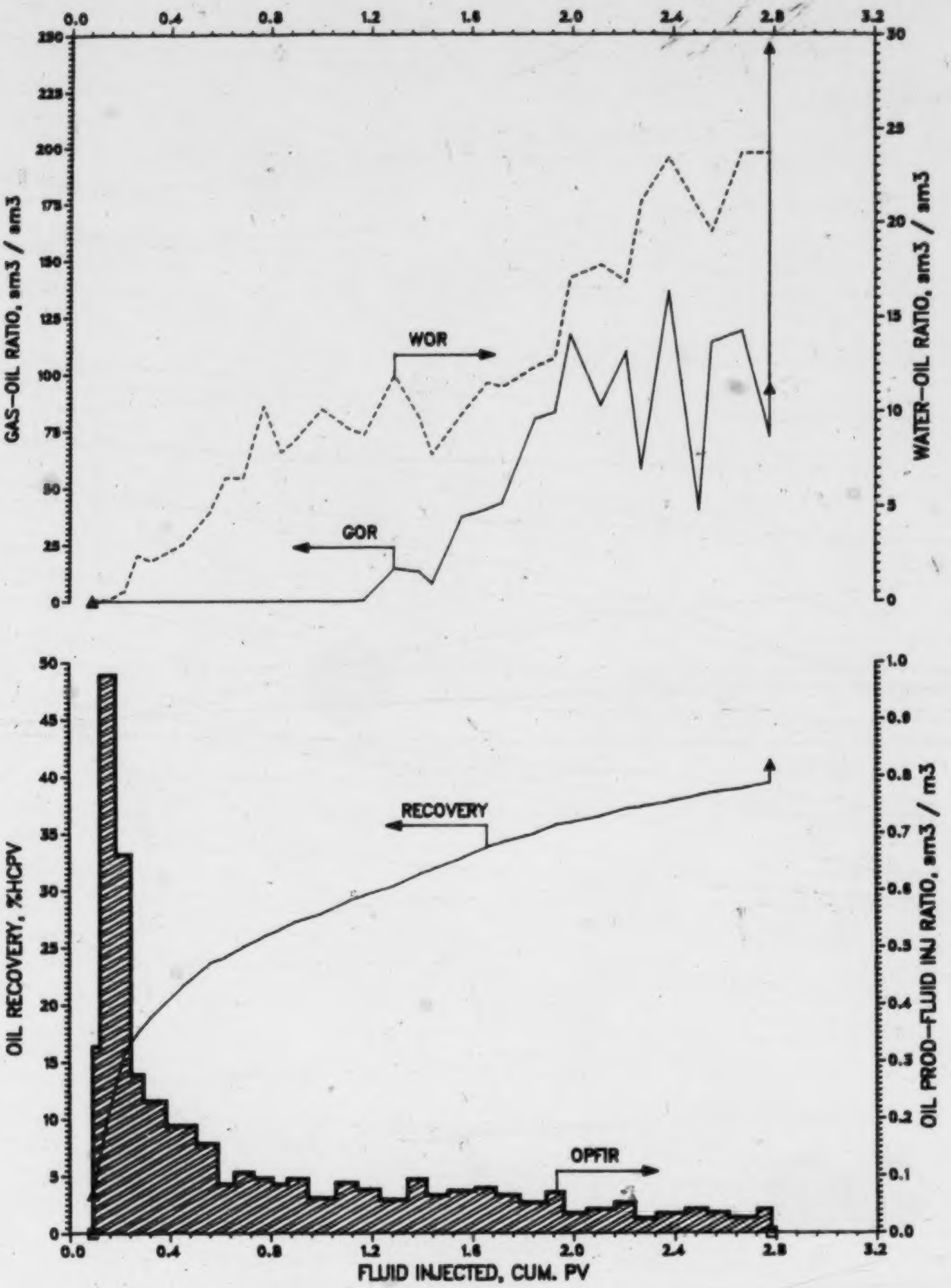
Figure C.22 Production History of Run LC22.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 150.0 mPa.s
ϕ = 36.22 %, k = 11.457 darcies, S_o = 87.05 %, S_{wc} = 12.95 %

[2.29 HCPV WF=> 0.20 RHCPV C02 @ 1.00 MPa (0.05 g—mol) 4:1 WAG, Wainwright]

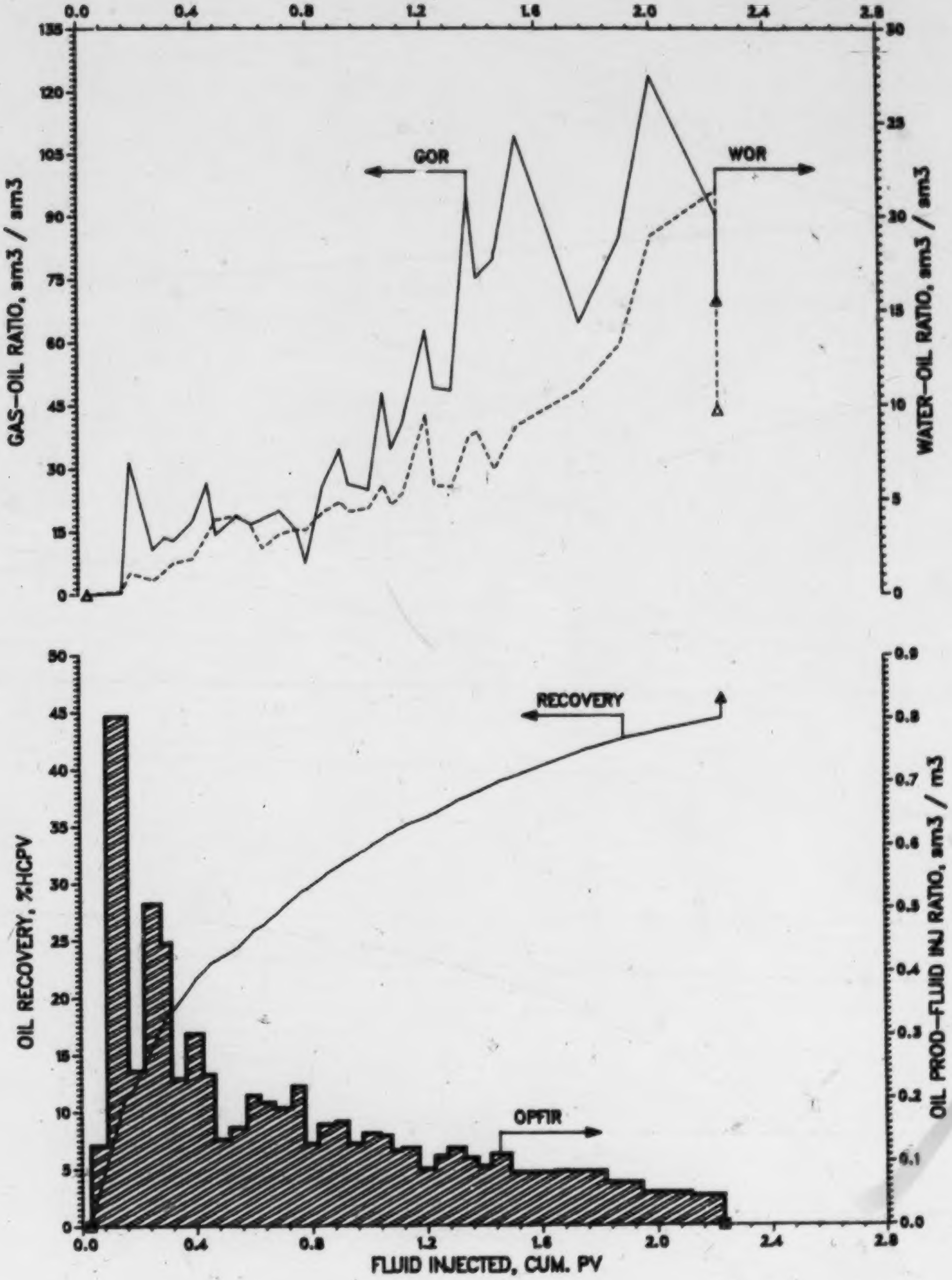
Figure C. 23 Production History of Run LC23(a,b).



NOTE: Average Run Conditions: Quarter of a 5–Spot, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.776 m/d, μ_o = 3295.0 mPa.s
ϕ = 43.12 %, k = 7.617 darcies, S_o = 86.76 %, S_{wc} = 13.24 %

[0.61 HCPV CO2 @ 2.50 MPa (1.41 g–mol) 4:1 WAG, 10–Slugs, SENLAC]

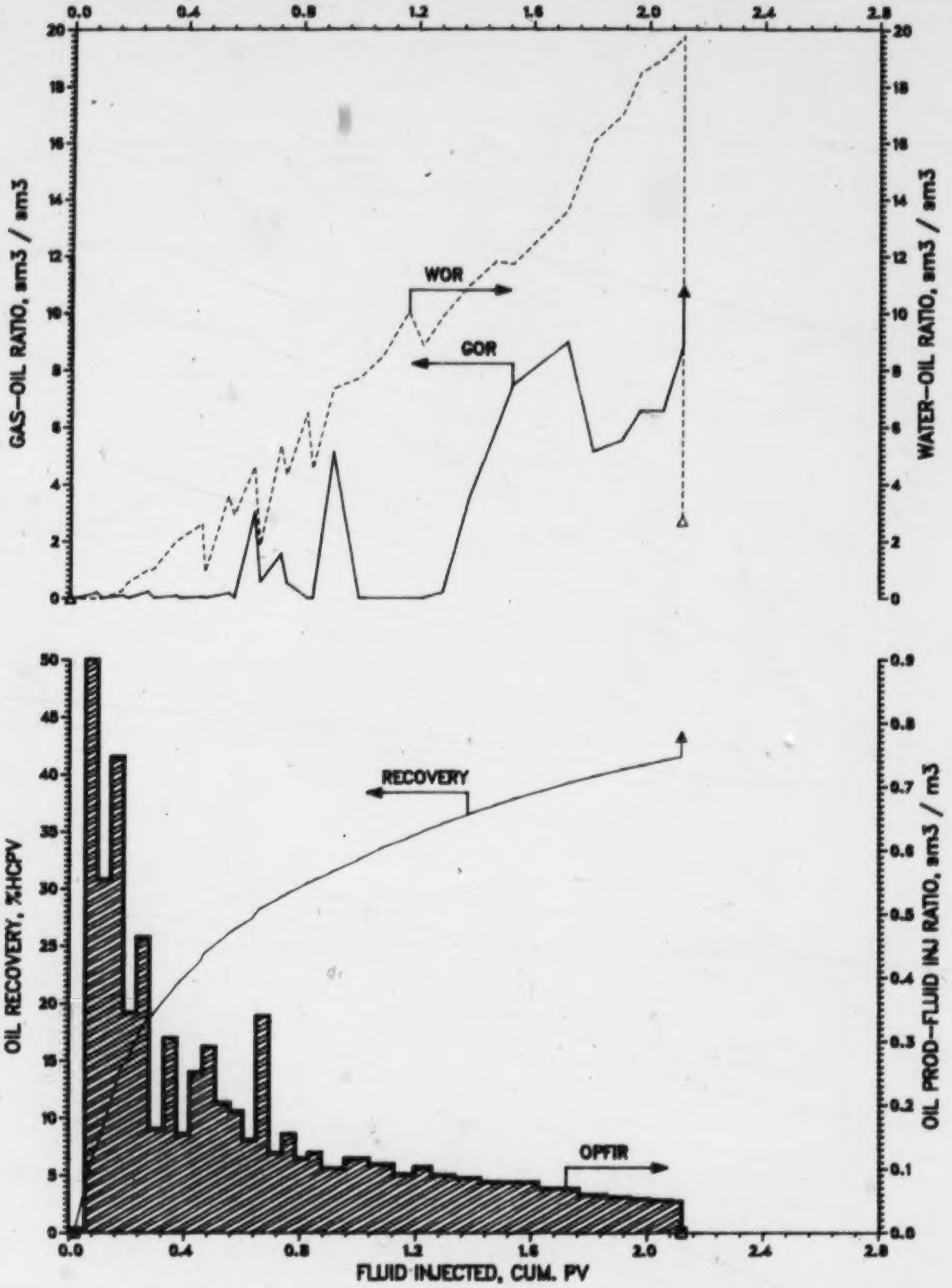
Figure C. 24 Production History of Run TD 1.



NOTE: Average Run Conditions: Quarter of a 5-Spot, 4.10 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.776 m/d, μ_o = 3295.0 mPa.s
ϕ = 41.52 %, k = 7.405 darcies, S_o = 90.11 %, S_{wc} = 9.89 %

[0.33 HCPV CO2 @ 4.10 MPa (1.41 g-mol) 4:1 WAG, 10-Slugs, SENLAC]

Figure C.25 Production History of Run TD 2.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.831 m/d, μ_o = 1055.3 mPa.s
ϕ = 40.59 %, k = 13.312 darcies, S_o = 91.33 %, S_{wc} = 8.67 %

[0.20 HCPV CO2 @ 1.00 MPa (0.16 g–mol) 4:1 WAG, 10–Slugs]

Figure C.26 Production History of Run TD 3.

Appendix D

Data Processing Programs

```
      PROGRAM PROCES
C
C                                           BY: STEVE DYER
C                                           & AMRO HAMZA
C                                           DATE: JUNE/1987
C
C
C
C  This is a data processing program for CO2 immiscible
C flooding. The program utilizes the Starling Equation of
C State for gas at every data point.
C
C  The data is contained in a separate data file. The name
C of the data file ("fdname") is entered during run time
C and must be no more than seven characters long. The data
C in the file are read in the following order:
C
C       NTABLE,NRUN,NFIG
C       TITLE
C       OVIS,PV,HCPV,PHI,SWC,SOI,KABS,MVA,TEMP
C       SSC,IWR,ARC,AFV
C       N
C       PI(1),PP(1),BI(1),GI(1),BP(1),OP(1),GP(1)
C      "  ,  "  ,  "  ,  "  ,  "  ,  "  ,  "
C       PI(N),PP(N),BI(N),GI(N),BP(N),OP(N),GP(N)
C
C   The first two lines contain information for the heading
C  on the table and plot.
C   NTABLE=> Table Number
C    NRUN => Run Number
C    NFIG => Figure Number (plot)
C   TITLE => Comment about the run
C
C  The third and fourth line contain all the constants
C and are defined as follows:
C
C   OVIS => Oil Viscosity [MPa.s]
C    PV  => Pore Volume [cm3]
C   HCPV => Hydrocarbon Pore Volume [cm3]
C    PHI => Porosity [%]
C    SWC => Connate Water Saturation [%]
C    SOI => Initial Oil Saturation [%]
C   KABS => Absolute Permeability [darcies]
C    MVA => Molar Density @ Atmospheric Conditions [Kmol/m3]
C   TEMP => Average Run Temperature [K]
C    SSC => Slug Size of CO2 [% HCPV]
C    IWR => Wag Ratio
C    ARC => Average Run Pressure [MPag]
C    AFV => Average Flow Velocity [meters per day]
C
C  The fifth line contains the number of samples
C entered in the data file (N).
```

```
C
C  The next N lines contain the operating and production
C data and are defined as follows:
C
C      PI => Injection Pressure [MPag]
C      PP => Production Pressure [MPag]
C      BI => Incremental Brine Injected [cm3]
C      GI => Incremental Gas Injected [cm3]
C      BP => Incremental Brine Produced [cm3]
C      OP => Incremental Oil Produced [cm3]
C      GP => Incremental Gas Produced [std. litres]
C
C  The following variables are calculated in the program
C for each row of data:
C
C    VFI=BI+GI => Total Volume of Fluids Injected [cm3]
C    RVP=VFI/PV => Ratio of VFI to PV [cm3/cm3]
C    NP=Sum.(OP) => Cumulative Oil Produced [cm3]
C    PREC=(NP/HCPV)*100.0 => Percent Recovery
C    GOR=GP*1000.0/OP => Instantaneous Gas-Oil-Ratio [Sm3/m3]
C    WOR=BP/OP => Instantaneous Water-Oil-Ratio [m3/m3]
C    OPFIR=OP/(BI+GI)
C            => Oil Produced-Fluid Injected Ratio [m3/m3]
C    MV => Starling => Molar Density of CO2 @ PI [Kmol/m3]
C    NMOL=MV*GI*1.0E-03 => Number of Moles of gas injected [mol]
C    CDRI=(NMOL/MVA)*1.0E+03
C            => Volume of CO2 @ atmospheric condition
C  * CDRT=Sum.(CDRI) => Cumulative Volume of CO2
C  * CDR=CDRT/NP => Cumulative CO2-Oil-Ratio [Sm3/m3]
C
C  * CDRET=( (GAS INJ-GAS PROD) / GAS INJ ) * 100.0
C        => Carbon Dioxide Retention [%]
C
C  * Only calculated once per run.
C
C  The Starling Equation of State uses injection pressure (PI)
C and the temperature (TEMP) to calculate the molar density
C (MV) [Kmol/m3].
C
      REAL MVA,NP,MV,NMOL,KABS,NPT,GPT,CDR,CDRT,CDRET
      REAL OPFIR
      LOGICAL USED
      CHARACTER*1 ANS,ANSC,ANSWER
      CHARACTER*10 FDDAT,FDTAB,FDTAG
      CHARACTER*66 BL
      CHARACTER*72 TITLE,BLANK,NTITLE
      DIMENSION VFI(50),RVP(50),PREC(50),GOR(50),WOR(50)
      DIMENSION OPFIR(50),MV(50),NMOL(50),CDRI(50),NP(50)
      DIMENSION PI(50),PP(50),BI(50),GI(50),BP(50),OP(50)
      DIMENSION GP(50),RVPT(50)
      DATA BLANK /' '/
      DATA IGMAX,IWMAX,INMAX,XOMAX,PMAX /0,0,0,0.0,0.0/
      DATA IGSTEP,IWSTEP,INSTEP,XOSTEP,PSTEP /0,0,0,0.0,0.0/
      DATA ZERO /0.0/
C
C***********************************************************
C*              DATA ENTRY                                 *
C***********************************************************
C
C  ASKING THE USER FOR THE NAME OF THE DATA FILE WHICH MUST
C BE LESS THAN TEN CHARACTERS LONG.
C
    1 WRITE(*,*) 'ENTER THE NAME OF THE DATA FILE ('' '')'
      READ(*,*) FDDAT
      WRITE(*,10) FDDAT
   10 FORMAT(' IS THE NAME OF THE DATA FILE ',A8,' (''Y''/''N'
     #')')
      READ(*,*) ANS
      IF(ANS.EQ.'N') GOTO 1
C
C  TAKING THE FIRST PART OF THE DATA FILE NAME (UP TO THE
C  PERIOD), AND CREATING NEW NAMES FOR THE TABLE, TAG, AND
C  PLOT FILES.
C
C  FINDING THE END OF THE COMMENT. IJ WILL CONTAIN
C  THE NUMBER OF CHARACTERS IN THE COMMENT ('TITLE').
C
      DO 32 IK=1,10
      IF(FDDAT(IK:IK).EQ.'.') GOTO 31
   32 CONTINUE
   31  FDTAB=FDDAT(:IK)//'TAB'
       FDTAG=FDDAT(:IK)//'TAG'
C
C  OPENING AND READING THE DATA FILE.
C
      OPEN(UNIT=10,FILE=FDDAT,STATUS='OLD')
      READ(10,*) NTABLE,NRUN,NFIG
      READ(10,12) TITLE
   12 FORMAT(A72)
C
C  FINDING THE END OF THE COMMENT. IJ WILL CONTAIN
C  THE NUMBER OF CHARACTERS IN THE COMMENT ('TITLE').
C
      DO 14 IJ=0,72,2
      IF(TITLE(IJ:IJ+2).EQ.' ') GOTO 15
   14 CONTINUE
   15 READ(10,*) OVIS,PV,HCPV,PHI,SWC,SOI,KABS,MVA,TEMP
      READ(10,*) SSC,IWR,ARP,AFV
C
C  MAKING SURE THE CONSTANTS ARE READ IN CORRECTLY
C
   16 WRITE(*,17) OVIS
      WRITE(*,18) PV
      WRITE(*,19) HCPV
      WRITE(*,20) PHI
      WRITE(*,21) SWC
      WRITE(*,22) SOI
      WRITE(*,23) KABS
      WRITE(*,24) MVA
      WRITE(*,25) TEMP
      WRITE(*,26) SSC
      WRITE(*,27) IWR
      WRITE(*,28) ARP
      WRITE(*,29) AFV
   17 FORMAT(' ',' 1) Oil Viscosity [MPa.s] = ',F6.1)
   18 FORMAT(' ',' 2) Pore Volume [cm3] = ',F6.1)
   19 FORMAT(' ',' 3) Hydrocarbon Pore Volume [cm3] = ',F6.1)
   20 FORMAT(' ',' 4) Porosity [%] = ',F5.2)
   21 FORMAT(' ',' 5) Connate Water Saturation [%] = ',F5.2)
   22 FORMAT(' ',' 6) Initial Oil Saturation [%] = ',F5.2)
   23 FORMAT(' ',' 7) Absolute Permeability [darcies] = ',F7.4)
   24 FORMAT(' ',' 8) Molar Density (@ atm.) [kmol/m3] = ',F8.5)
   25 FORMAT(' ',' 9) Average Run Temperature [K] = ',F6.2)
   26 FORMAT(' ','10) Slug Size [% HCPV] = ',F5.2)
   27 FORMAT(' ','11) Wag Ratio [BRINE:CO2] = ',I2,':1')
   28 FORMAT(' ','12) Average Run Pressure [MPag] = ',F4.2)
   29 FORMAT(' ','13) Average Flow Velocity [m/d] = ',F5.3)
C
C     THE CORRECTIONS ARE MADE TO THE OUTPUT FILE BUT ARE
C     NOT CORRECTED IN THE DATA FILE.
C
      WRITE(*,*)
   30 WRITE(*,*)' ARE THERE ANY CORRECTIONS (''Y''/''N'') ?'
      READ(*,*) ANSC
      IF(ANSC.EQ.'N') GOTO 50
      WRITE(*,*) 'WHICH CONSTANT WOULD YOU LIKE TO CHANGE ?'
      READ(*,*) NCOR
C
C     CHECKING TO SEE THAT NCOR ISN'T GREATER THAN THE NUMBER
C     OF CONSTANTS.
C
      IF(NCOR.GT.13) GOTO 30
C
C     THIS IF STATEMENT MATCHES NCOR WITH THE RIGHT VARIABLE
C     THAT HAS TO BE CORRECTED. AFTER MAKING THE CORRECTION
C     THE CONSTANTS ARE WRITTEN AGAIN AND THE USER CAN MAKE
C     MORE CORRECTIONS.
C
      IF(NCOR.EQ.1) THEN
       WRITE(*,*)'Oil Viscosity'
       READ(*,*) OVIS
      ELSEIF(NCOR.EQ.2) THEN
       WRITE(*,*)'Pore Volume'
       READ(*,*) PV
      ELSEIF(NCOR.EQ.3) THEN
       WRITE(*,*)'Hydrocarbon Pore Volume'
       READ(*,*) HCPV
      ELSEIF(NCOR.EQ.4) THEN
       WRITE(*,*)'Porosity'
       READ(*,*) PHI
      ELSEIF(NCOR.EQ.5) THEN
       WRITE(*,*)'Connate Water Saturation'
       READ(*,*) SWC
      ELSEIF(NCOR.EQ.6) THEN
       WRITE(*,*)'Initial Oil Saturation'
       READ(*,*) SOI
      ELSEIF(NCOR.EQ.7) THEN
       WRITE(*,*)'Absolute Permeability'
       READ(*,*) KABS
      ELSEIF(NCOR.EQ.8) THEN
       WRITE(*,*)'Molar Density'
       READ(*,*) MVA
      ELSEIF(NCOR.EQ.9) THEN
       WRITE(*,*)'Average Run Temperature'
       READ(*,*) TEMP
      ELSEIF(NCOR.EQ.10) THEN
       WRITE(*,*)'Slug Size'
       READ(*,*) SSC
      ELSEIF(NCOR.EQ.11) THEN
       WRITE(*,*)'Wag Ratio'
       READ(*,*) IWR
      ELSEIF(NCOR.EQ.12) THEN
       WRITE(*,*)'Average Run Pressure'
       READ(*,*) ARP
      ELSEIF(NCOR.EQ.13) THEN
       WRITE(*,*)'Average Flow Velocity'
       READ(*,*) AFV
      ENDIF
      GOTO 16
C
C    N CONTAINS THE NUMBER OF DATA POINTS
C
   50 READ (10,*) N
      DO 34 I=1,N
       READ(10,*) PI(I),PP(I),BI(I),GI(I),BP(I),OP(I),GP(I)
   34 CONTINUE
C
C************************************************************
C*             CALCULATION SECTION                         *
C************************************************************
C
C   INITIALIZING CONSTANTS
C
      NPT=0.0
      CDRT=0.0
      CDRET=0.0
      RVT=0.0
      GMAX=0.0
      WMAX=0.0
      XOMAX=0.0
C
C  BEGINING THE CALCULATIONS USING THE DATA THAT WAS READ IN.
C  THIS SECTION ALSO CALLS "STAR" WHICH CONTAINS THE
C  THE STARLING EQUATION OF STATE. STAR UTILIZES THE
C  SECANT ROOT FINDING METHOD.
C
C  RVT, NPT, AND CDRT ARE TEMPORARY TOTALS FOR THE ARRAYS
C  RVPT,NP, AND CDRI RESPECTIVELY. THESE TEMPORARY VARIABLES
C  ARE NEEDED TO FIND THE TOTAL. TOTALS ARE FOUND BY ADDING
C  THE PREVIOUS
C  AND TO FIND,THE TOTAL THE PREVIOUS VALUE MUST BE ADDED
C  TO THE PRESENT TOTAL.
C     THE VARIABLES ENDING IN '-MAX' CONTAIN THE MAXIMUM
C  VALUE OF THE VARIABLE. THIS MAXIMUM WILL BE USED LATER
C  FOR THE TAG FILE.
C
      DO 200 I=1,N
      VFI(I)=BI(I)+GI(I)
      RVP(I)=VFI(I)/PV
      RVPT(I)=RVT+RVP(I)
      RVT=RVPT(I)
      NP(I)=NPT+OP(I)
      NPT=NP(I)
      PREC(I)=(NP(I)/HCPV)*100.0
      GOR(I)=GP(I)*1000.0/OP(I)
       IF(GOR(I).GT.GMAX) GMAX=GOR(I)
      WOR(I)=BP(I)/OP(I)
       IF(WOR(I).GT.WMAX) WMAX=WOR(I)
       IF(VFI(I).EQ.0.0) THEN
      OPFIR(I)=99.99
       ELSE
      OPFIR(I)=OP(I)/VFI(I)
       IF(OPFIR(I).GT.XOMAX) XOMAX=OPFIR(I)
       ENDIF
      CALL STAR(MV(I),PI(I),TEMP)
      NMOL(I)=MV(I)*GI(I)*1.0E-3
      CDRI(I)=(NMOL(I)/MVA)*1.0E+3
      CDRT=CDRT+CDRI(I)
      GPT=GPT+GP(I)
  200 CONTINUE
      XNMAX=PREC(N)
      PMAX=RVPT(N)
      CDR=CDRT/NP(N)
      IF(CDRT.EQ.0.0)THEN
      CDRET=0.00
      ELSE
      CDRET=((CDRT-(GPT*1000.0))/CDRT)*100.0
      ENDIF
C
```

```
C*************************************************************
C*               TABULATING RESULTS                          *
C*************************************************************
C
C  PREPARING THE TABULATED OUTPUT FILE. THE FILE MUST
C  BE NON-EXISTING OR THE PROGRAM WILL ASK YOU FOR A
C  NEW FILE NAME. THE SECOND TIME THROUGH THE PROGRAM
C  THE TAG AND PLT FILES WILL HAVE BEEN ALREADY CREATED.
C  TO TAKE CARE OF THIS THE PROGRAM WILL ASK YOU IF YOU
C  WANT TO PLOT THE LABELS (THE REASON WHY THE PROGRAM
C  IS BEING RUN THE SECOND TIME). IF YOU ANSWER NO ('N'),
C  AND YOU ARE ONLY RUNNING THE PROGRAM AGAIN TO SEE ANY
C  CORRECTIONS THAT WHERE MADE IN THE DATA FILE, THEN
C  THE PROGRAM WILL PROMPT YOU FOR ANOTHER NAME. IF YOU
C  ANSWER YES ('Y') THEN THE PROGRAM WILL OPEN THE FILES
C  (TAG AND PLT) AS 'OLD' AND THEN CLOSE THEM AS 'DELETE'
C  TO DELETE THE FILE.
C
   36 OPEN(UNIT=11,FILE=FDTAB,STATUS='NEW',IOSTAT=IERR)
      IF(IERR.EQ.0) THEN
       ANSWER='N'
       GOTO 37
       ENDIF
      WRITE(*,*)'DO YOU WANT TO PLOT THE LABELS(''Y''/''N'')'
      READ(*,*) ANSWER
      IF(ANSWER.EQ.'Y') THEN
      OPEN(UNIT=12,FILE=FDTAG,STATUS='OLD',IOSTAT=IERR)
      CLOSE(UNIT=12,STATUS='DELETE')
      GOTO 501
       ELSE
      WRITE(*,*)' THIS FILE ALREADY EXISTS, PLEASE ENTER'//
     #' THE NAME OF A NON-EXISTING FILE.'
      WRITE(*,*)'WHAT IS THE NAME OF THE OUTPUT FILE ('' '')?'
      READ(*,*) FDTAB
      GOTO 36
      ENDIF
C
C  CALCULATING THE NUMBER OF PAGES TO FIT 17 LINES OF DATA
C  ON EACH PAGE, NOT INCLUDING THE TITLE,CONSTANTS,OR HEADINGS.
C    NPAGE => NUMBER OF PAGES TO BE PRINTED.
C    ILAST => CONTAINS A NUMBER BETWEEN 1 & N.
C
   37 NPAGE=NINT((N/17)+.5)
      I1=1
      ILAST=17
      DO 500 IPAGE=1,NPAGE
C
C  AFTER THE FIRST PAGE, WHEN THE PROGRAM RETURNS TO THIS
C  POINT, A ONE WILL BE PRINTED FOR A NEW PAGE.
C    (FIRST PAGE WHEN IPAGE=1)
C
      IF(IPAGE.EQ.1) THEN
```

```
       WRITE(11,38)
      ELSE
       WRITE(11,38)
   38  FORMAT('1')
       WRITE(11,*)
      ENDIF
      WRITE(11,*)
      WRITE(11,*)
      WRITE(11,*)
      WRITE(11,*)
      WRITE(11,*)
      WRITE(11,*)
      WRITE(11,*)
C
C    PRINTING OUT THE TITLE AT THE TOP OF THE PAGE. AFTER THE
C    FIRST PAGE '(CONTINUED)' WILL BE CONTAINED AT THE TOP.
C
      IF(IPAGE.EQ.1) THEN
       WRITE(11,405) NTABLE
  405  FORMAT(62X,'TABLE A',I2)
      ELSE
       WRITE(11,406) NTABLE
  406  FORMAT(56X,'TABLE A',I2,' (CONTINUED)')
      ENDIF
      WRITE(11,*)
      WRITE(11,410) NRUN
  410 FORMAT(57X,'RESULTS OF RUN LC',I2)
C
C    CENTERING THE COMMENT TO FIT 132 COLUMN PAPER. BLANK
C    CONTAINS BLANKS WHICH ARE ADDED (//) TO THE FRONT OF
C    THE COMMENT.
C
      WRITE(11,*) BLANK(:66-(IJ/2))//TITLE(:IJ)
      WRITE(11,*)
      WRITE(11,*)
C
C    THE CONSTANTS ARE WRITTEN ON EVERY PAGE.
C
      WRITE(11,421) PHI,PV,SWC
  421 FORMAT(1X,'Porosity [%] = ',F5.1,24X,
     1'Pore Volume [cm3] = ',F6.1,18X,
     2'Connate Water Saturation [%] = ',F5.1)
      WRITE(11,422) OVIS,SOI,MVA
  422 FORMAT(1X,'Oil Viscosity [mPa.s] = ',F6.1,14X,
     1'Initial Oil Saturation [%] = ',F5.1,10X,
     2'Molar Density @ atm. [kmol/m3] = ',F8.5)
      WRITE(11,423) TEMP,HCPV,KABS
  423 FORMAT(1X,'Average Run Temperature [K] = ',F6.2,8X,
     1'Hydrocarbon Pore Volume [cm3] = ',F6.1,6X,
     2'Absolute Permeability [darcies] = ',F7.4)
      WRITE(11,424) CDR,CDRET,AFV
  424 FORMAT(1X,'Carbon Dioxide Required [sm3/sm3] = ',F6.2,
     12X,'Carbon Dioxide Retention [%inj] = ',F5.2,5X,
     2'Average Flow Velocity [m/d] = ',F5.3)
      WRITE(11,*)
      WRITE(11,*)
C
C    PRINTING THE RESULTS OF THE RUN
C
      WRITE(11,415)
  415 FORMAT(2X,'PRESS',5X,'PRESS',6X,'GAS',6X,'WATER',4X,
     1'VFI/PV',6X,'GAS',6X,'WATER',6X,'OIL',5X,'CUM OIL',
     23X,'PERCENT',5X,'WOR',7X,'GOR',6X,'OPFIR')
      WRITE(11,416)
  416 FORMAT(3X,'inj',7X,'prod ',5X,'inj',7X,'inj',7X,'--',
     1,8X,'prod',5X,'prod',6X,'prod',6X,
     2'prod',5X,'Recovery',5X,'--',8X,'--',8X,'--')
      WRITE(11,417)
  417 FORMAT(2X,'(MPa)',5X,'(MPa)',5X,'(cm3)',5X,'(cm3)',
     13X,'(cm3/cm3)',3X,'(s.ltr)',3X,'(cm3)',5X,'(cm3)',
     25X,'(cm3)',6X,'(%)',4X,'(sm3/sm3)',
     32X,'(sm3/sm3)',2X,'(sm3/m3)')
C
C   SETTING ILAST EQUAL TO N ON THE LAST PAGE.
C
      IF(IPAGE.EQ.NPAGE) THEN
       ILAST=N
      ENDIF
      DO 40 J=I1,ILAST
      WRITE(11,*)
C
C  CHECKS TO SEE IF BLOW DOWN IS REACHED (OPFIR = 99.99).
C
      IF(OPFIR(J).EQ.99.99) THEN
C
C   TWO WRITE STATEMENTS ARE USED; ONE TO TAKE CARE OF
C   BLOW DOWN AND THE OTHER FOR NORMAL OUT PUT (RESPECTIVELY).
C
      WRITE(11,418) PI(J),PP(J),GI(J),BI(J),RVP(J),GP(J),BP(J),
     1OP(J),NP(J),PREC(J),WOR(J),GOR(J)
  418 FORMAT(3X,F4.2,6X,F4.2,5X,F5.1,4X,F6.1,
     15X,F5.3,6X,F5.3,3X,F6.2,4X,F6.2,4X,
     2F6.2,4X,F6.2,5X,F5.2,4X,F7.2)
CC
      ELSE
      WRITE(11,419) PI(J),PP(J),GI(J),BI(J),RVP(J),GP(J),BP(J),
     1OP(J),NP(J),PREC(J),WOR(J),GOR(J),OPFIR(J)
  419 FORMAT(3X,F4.2,6X,F4.2,5X,F5.1,4X,F6.1,
     15X,F5.3,6X,F5.3,3X,F6.2,4X,F6.2,4X,
     2F6.2,4X,F6.2,5X,F5.2,4X,F7.2,4X,F5.3)
      ENDIF
   40 CONTINUE
C
C   INCREAMENTING THE DO LOOP FOR THE RESULTS (NOT THE PAGE).
```

```
C
      I1=ILAST+1
      ILAST=(IPAGE+1)*17
  500 CONTINUE
C
C***************************************************************
C*               PLOTTING THE RESULTS                          *
C***************************************************************
C
C  OPENING AND READING THE TAG FILE WHICH WILL CONTAIN THE
C  NECESSARY COMMANDS FOR *TELLAGRAF TO PLOT THE GRAPHS.
C
  501 OPEN(UNIT=12,FILE=FDTAG,STATUS='NEW',IOSTAT=IERR)
C
C  CHECKING TO SEE IF THE FILE ALREADY EXISTS. IF IT DOES
C  THEN THE COMPUTER WILL ASK YOU FOR ANOTHER FILE NAME.
C
      IF(IERR.NE.0) THEN
      WRITE(*,*)' THIS FILE ALL READY EXISTS, PLEASE ENTER'//
     #' THE NAME OF A NON-EXISTING FILE.'
C
C  ASKING THE USER FOR THE NAME OF THE PLOT FILE WHICH MUST
C BE LESS THAN TEN CHARACTERS LONG.
C
      WRITE(*,*) 'ENTER THE NAME OF THE TAG FILE ('' '')'
      READ(*,*) FDTAG
      GOTO 501
      ENDIF
C
C NTITLE CONTAINS THE CENTERED COMMENT.
C
      NTITLE=BLANK(:40-(IJ/2))//TITLE(:IJ)
C
C  FINDING THE MAXIMUM POINT AND THE STEP SIZE BY
C  USING THE MAXX SUBROUTINE.
C     THE NUMBERS ARE PASSED:  REAL,REAL,INTEGER,INTEGER
C     IF THE NUMBERS ON THE AXIS ARE INTEGERS THE FORM
C     TO USE WOULD BE CALL MAXX(0.0,0.0,INTEGER,INTEGER).
C     IF THE NUMBERS ON THE AXIS ARE REAL THE FORM TO
C     USE WOULD BE CALL MAXX(REAL,REAL,0,0).
C
 1015 INMAX=10*NINT(XNMAX/10.0+0.5)
      IGMAX=10*NINT(GMAX/10.0+0.5)
      IWMAX=10*NINT(WMAX/10.0+0.5)
      CALL MAXX(0.0,0.0,IGMAX,IGSTEP)
      CALL MAXX(0.0,0.0,IWMAX,IWSTEP)
      CALL MAXX(0.0,0.0,INMAX,INSTEP)
      CALL MAXX(XOMAX,XOSTEP,0,0)
      CALL MAXX(PMAX,PSTEP,0,0)
      PMAX=FLOAT(NINT(PMAX*5.5+.5))/5.0
C
C FINDING THE LOCATION FOR THE LABELS
```

```
C
      IF(ANSWER.EQ.'N') GOTO 522
      WRITE(*,*)'WHAT ARE THE X AND Y COORDINATES FOR THE'//
     1' GOR LABEL ?'
      READ(*,*) GX,GY
      WRITE(*,*)'WHAT ARE THE X AND Y COORDINATES FOR THE'//
     1' WOR LABEL ?'
      READ(*,*) WX,WY
      WRITE(*,*)'WHAT ARE THE X AND Y COORDINATES FOR '//
     1  'THE RECOVERY LABEL?'
      READ(*,*) RX,RY
      WRITE(*,*)'WHAT ARE THE X AND Y COORDINATES FOR'//
     1  ' THE OPFIR LABEL ?'
      READ(*,*) OX,OY
 1018 WRITE(*,*)
      WRITE(*,1020) GX,GY
      WRITE(*,1022) WX,WY
      WRITE(*,1024) RX,RY
      WRITE(*,1026) OX,OY
 1020 FORMAT(' ','1) THE X AND Y FOR GOR ARE X = ',F6.4,
     1' Y = ',F7.3)
 1022 FORMAT(' ','2) THE X AND Y FOR WOR ARE X = ',F6.4,
     1' Y = ',F7.3)
 1024 FORMAT(' ','3) THE X AND Y FOR RECOVERY ARE X = ',F6.4,
     1' Y = ',F7.3)
 1026 FORMAT(' ','4) THE X AND Y FOR OPFIR ARE X = ',F6.4,
     1' Y = ',F7.3)
C
C    THIS SECTION CORRECTS THE X AND Y FOR THE LABELS
C
      WRITE(*,*)
 1030 WRITE(*,*)' ARE THERE ANY CORRECTIONS (''Y''/''N'') ?'
      READ(*,*) ANSC
      IF(ANSC.EQ.'N') GOTO 522
      WRITE(*,*) 'WHICH CONSTANT WOULD YOU LIKE TO CHANGE ?'
      READ(*,*) NCOR
C
C    CHECKING TO SEE THAT NCOR ISN'T GREATER THAN THE NUMBER
C    OF CONSTANTS.
C
      IF(NCOR.GT.4) GOTO 1030
      IF(NCOR.EQ.1) THEN
          WRITE(*,*)' THE GOR LABEL'
          READ(*,*) GX,GY
      ELSEIF(NCOR.EQ.2) THEN
          WRITE(*,*)' THE WOR LABEL'
          READ(*,*) WX,WY
      ELSEIF(NCOR.EQ.3) THEN
          WRITE(*,*)' THE RECOVERY LABEL'
          READ(*,*) RX,RY
      ELSEIF(NCOR.EQ.4) THEN
          WRITE(*,*)' THE OPFIR LABEL'
```

```
           READ(*,*) OX,OY
      ENDIF
      GOTO 1030
  522 CONTINUE
C
C THIS SECTION DRAWS THE GOR CURVE. BOTH THE X AXIS AND
C THE Y AXIS ARE PLOTTED.
C
      WRITE(12,*)'GENERATE A PLOT.'
      WRITE(12,*)'WINDOW DESTINATION IS 0.77 7.7 5.65 11.15.'
      WRITE(12,*)'X AXIS LENGTH IS 10.0.'
      WRITE(12,*)'X AXIS EXISTENCE IS 1.'
      WRITE(12,*)'X AXIS MODE IS REVERSED.'
      WRITE(12,*)'X AXIS OFFSET IS 7.0.'
      WRITE(12,*)'X AXIS TICK MARKS IS 5.'
      WRITE(12,550) PSTEP
  550 FORMAT(' ',' X AXIS STEP SIZE IS ',F3.1,'.')
      WRITE(12,*)'X AXIS INTEGERIZE OFF.'
      WRITE(12,503) PMAX
  503 FORMAT(' ','X AXIS MIN IS 0.0, X AXIS MAX IS ',F4.1,'.')
      WRITE(12,*)'X AXIS ORIGIN IS 0.0.'
      WRITE(12,*)'Y AXIS ORIGIN IS 1.5.'
      WRITE(12,*)'Y AXIS EXISTENCE IS 1.'
      WRITE(12,504) IGMAX
  504 FORMAT(' ','Y AXIS MIN IS 0, Y AXIS MAX IS ',I4,'.')
      WRITE(12,551) IGSTEP
  551 FORMAT(' ','Y AXIS STEP SIZE IS ',I3,'.')
      WRITE(12,*)'Y AXIS TICK-MARKS IS 10.'
      WRITE(12,506)
  506 FORMAT(' ','Y AXIS LABEL TEXT "GAS-OIL RATIO, sm3 / sm3".')
      WRITE(12,*)'INPUT DATA.'
      WRITE(12,*)'"GOR"'
      WRITE(12,512) (RVPT(J1),GOR(J1),J1=1,N)
  512 FORMAT(2(F7.2,' '))
      WRITE(12,*)'END OF DATA.'
      WRITE(12,*)'CURVE 1 COLOR BLACK.'
C
C  THIS SECTON IS FOR PLOTTING THE GOR LABEL
C     - OX AND OY CONTAIN THE X AND Y VALUE IN COORDINATE
C       UNITS.
C     - OX1 AND OY1 ARE THE OX AND OY VALUE IN INCHES
C       (MEASURED FROM THE ORIGIN).
C      NOTE:IF THE LENGTH OF EITHER AXIS IS CHANGED THEN
C         THEY SHOULD BE ALTERED IN  THE OX1 AND THE OY1
C         EQUATIONS TO LINE UP THE MESSAGES ON THE GRAPHS.
C         PRESENTLY THE LENGTHS OF THE X AND THE Y AXIS
C         ARE 10.0 AND 7.0 RESPECTIVELY.
C     - OX2 AND OY2 ARE THE X AND Y POINTER LOCATION (INCHES).
C       THE NUMBERS, 1.2477 AND .26, ARE THE LENGTH OF THE
C       POINTER AND THE STUB RESPECTIVELY.
C
      IF(ANSWER.EQ.'N') GOTO 530
      GX1=(GX*10.0)/PMAX
      GY1=(GY*7.0)/FLOAT(IGMAX)
      GX2=GX1-1.2477
      GY2=GY1+.26
C
C
C  MESSAGE 2 IS THE START OF THE POINTER.
C     MSG ARROW-HEAD > DEFINES THE TYPE OF ARROW-HEAD.
C     MSG CONNECT POINT > DEFINES THE LOCATION OF WHERE THE
C       POINTER IS TO EXTEND FROM (TC > TOP CENTER).
C     MSG POINTER > DEFINES THE LOCATION OF WHERE THE POINTER
C       SHOULD END.
C     MSG TEXT > DEFINES THE TEXT OF THE MESSAGE WHICH IS IN
C       THE QUOTES.
C     MSG UNITS > DEFINES THE UNITS WHICH ARE USED FOR MESSAGE
C       2. IN THIS CASE, PLOT INCHES, WILL PLOT IN INCHES
C       WITH THE ORIGIN OF THE GRAPH BEING THE POINT 0.0 0.0.
C     MSG X, Y > DEFINES THE LOCATION OF THE MESSAGE TEXT. THE
C       X AND Y ARE IN THE SAME UNITS WHICH ARE DEFINED IN
C       THE "MSG UNITS..." STATEMENT.
C  MESSAGE 3 CONTAINS THE LABEL OF THE CURVE.
C    NOTE: HERE THE MSG CONNECT POINT IS BR (BOTTOM RIGHT)
C        WHICH IS NOT THE SAME AS RB (RIGHT BOTTOM).
C     MSG X, Y > THE SAME AS THE ABOVE EXCEPT HERE IT IS OFF-
C       SET .04 INCHES IN THE Y DIRECTION.
C
      WRITE(12,*)'MESSAGE 2.'
      WRITE(12,*)'MSG ARROW-HEAD IS 1201.'
      WRITE(12,*)'MSG CONNECT POINT IS TC.'
      WRITE(12,510) GX2,GY2
  510 FORMAT(' ','MSG POINTER IS TC ',F6.4,' ',F6.4,'.')
      WRITE(12,*)'MSG TEXT IS " ".'
      WRITE(12,*)'MSG UNITS IS PLOT INCHES.'
      WRITE(12,511) GX1,GY1
  511 FORMAT(' ','MSG X IS ',F6.4,' , Y IS ',F6.4,'.')
      WRITE(12,*)'MESSAGE 3.'
      WRITE(12,*)'MSG CONNECT POINT IS BR.'
      WRITE(12,*)'MSG TEXT IS "GOR   ".'
      WRITE(12,*)'MSG HEIGHT IS 0.15.'
      WRITE(12,*)'MSG UNITS IS PLOT INCHES.'
      WRITE(12,513) GX1,(GY2+.04)
  513 FORMAT(' ','MSG X IS ',F6.4,' , Y IS ',F6.4,'.')
C
  530 CONTINUE
      WRITE(12,*)'SUBPLOT 1.'
C
C THIS SECTION DRAWS THE WOR CURVE. EVEN THOUGH
C ONLY THE Y AXIS IS PLOTTED, THE X AXIS SPECIFICATION MUST BE
C INCLUDED TO PLOT THE CURVE.
C
      WRITE(12,*)'GENERATE A PLOT.'
      WRITE(12,*)'WINDOW DESTINATION IS 0.77 7.7 5.65 11.15.'
      WRITE(12,*)'X AXIS LENGTH IS 10.0.'
      WRITE(12,*)'X AXIS EXISTENCE IS 0.'
      WRITE(12,601) PSTEP
  601 FORMAT(' X AXIS STEP SIZE IS ',F4.1,'.')
      WRITE(12,602) PMAX
  602 FORMAT(' ','X AXIS MIN IS 0.0, X AXIS MAX IS ',F3.1,'.')
      WRITE(12,*)'X AXIS ORIGIN IS 0.0.'
      WRITE(12,*)'Y AXIS EXISTENCE IS 1.'
      WRITE(12,*)'Y AXIS ORIGIN IS 1.5.'
      WRITE(12,*)'Y AXIS MODE IS REVERSED.'
      WRITE(12,*)'Y AXIS OFFSET IS 10.0.'
      WRITE(12,604) IWMAX
  604 FORMAT(' ','Y AXIS MIN IS 0, Y AXIS MAX IS ',I3,'.')
      WRITE(12,*)'Y AXIS TICK-MARKS IS 10.'
      WRITE(12,650) IWSTEP
  650 FORMAT(' ','Y AXIS STEP SIZE IS ',I2,'.')
      WRITE(12,606)
  606 FORMAT(' ','Y AXIS LABEL TEXT "WATER-OIL RATIO, sm3 / sm3".')
      WRITE(12,*)'INPUT DATA.'
      WRITE(12,*)'"WOR"'
      WRITE(12,614) (RVPT(J2),WOR(J2),J2=1,N)
  614 FORMAT(2(F5.2,' '))
      WRITE(12,*)'END OF DATA.'
      WRITE(12,*)'CURVE 1 COLOR RED.'
      WRITE(12,*)'CURVE 1 TEXTURE IS DASHED.'
C
C  THIS SECTON IS FOR PLOTTING THE WOR LABEL
C    - OX AND OY CONTAIN THE X AND Y VALUE IN COORDINATE
C      UNITS.
C    - OX1 AND OY1 ARE THE OX AND OY VALUE IN INCHES
C      (MEASURED FROM THE ORIGIN).
C     NOTE:IF THE LENGTH OF EITHER AXIS IS CHANGED THEN
C        THEY SHOULD BE ALTERED IN  THE OX1 AND THE OY1
C        EQUATIONS TO LINE UP THE MESSAGES ON THE GRAPHS.
C        PRESENTLY THE LENGTHS OF THE X AND THE Y AXIS
C        ARE 10.0 AND 7.0 RESPECTIVELY.
C    - OX2 AND OY2 ARE THE X AND Y POINTER LOCATION (INCHES).
C      THE NUMBERS, 1.2477 AND .26, ARE THE LENGTH OF THE
C      POINTER AND THE STUB RESPECTIVELY.
C
      IF(ANSWER.EQ.'N') GOTO 630
      WX1=(WX*10.0)/PMAX
      WY1=(WY*7.0)/FLOAT(IWMAX)
      WX2=WX1+1.2477
      WY2=WY1+.26
C
C
C  MESSAGE 2 IS THE START OF THE POINTER.
C     MSG ARROW-HEAD > DEFINES THE TYPE OF ARROW-HEAD.
C     MSG CONNECT POINT > DEFINES THE LOCATION OF WHERE THE
C       POINTER IS TO EXTEND FROM (TC > TOP CENTER).
C     MSG POINTER > DEFINES THE LOCATION OF WHERE THE POINTER
```

```
C         SHOULD END.
C       MSG TEXT > DEFINES THE TEXT OF THE MESSAGE WHICH IS IN
C         THE QUOTES.
C       MSG UNITS > DEFINES THE UNITS WHICH ARE USED FOR MESSAGE
C         2. IN THIS CASE, PLOT INCHES, WILL PLOT IN INCHES
C         WITH THE ORIGIN OF THE GRAPH BEING THE POINT 0.0 0.0.
C       MSG X, Y > DEFINES THE LOCATION OF THE MESSAGE TEXT. THE
C         X AND Y ARE IN THE SAME UNITS WHICH ARE DEFINED IN
C         THE "MSG UNITS..." STATEMENT.
C   MESSAGE 3 CONTAINS THE LABEL OF THE CURVE.
C     NOTE: HERE THE MSG CONNECT POINT IS BL (BOTTOM LEFT)
C          WHICH IS NOT THE SAME AS LB (LEFT BOTTOM).
C       MSG X, Y > THE SAME AS THE ABOVE EXCEPT HERE IT IS OFF-
C         SET .04 INCHES IN THE Y DIRECTION.
C
      WRITE(12,*)'MESSAGE 2.'
      WRITE(12,*)'MSG ARROW-HEAD IS 1201.'
      WRITE(12,*)'MSG CONNECT POINT IS TC.'
      WRITE(12,615) WX2,WY2
  615 FORMAT(' ','MSG POINTER IS TC ',F6.4,' ',F6.4,'.')
      WRITE(12,*)'MSG TEXT IS " ".'
      WRITE(12,*)'MSG UNITS IS PLOT INCHES.'
      WRITE(12,616) WX1,WY1
  616 FORMAT(' ','MSG X IS ',F6.4,' , Y IS ',F6.4,'.')
      WRITE(12,*)'MESSAGE 3.'
      WRITE(12,*)'MSG CONNECT POINT IS BL.'
      WRITE(12,*)'MSG TEXT IS "  WOR".'
      WRITE(12,*)'MSG HEIGHT IS 0.15.'
      WRITE(12,*)'MSG UNITS IS PLOT INCHES.'
      WRITE(12,617) WX1,(WY2+.04)
  617 FORMAT(' ','MSG X IS ',F6.4,' , Y IS ',F6.4,'.')
C
  630 CONTINUE
      WRITE(12,*)'SUBPLOT 2.'
C
C THIS SECTION DRAWS THE RECOVERY CURVE. BOTH THE X AND
C Y AXIS ARE PLOTTED.
C
      WRITE(12,*)'GENERATE A PLOT.'
      WRITE(12,*)'WINDOW DESTINATION IS 0.77 7.7 0.65 6.15.'
      WRITE(12,*)'X AXIS LENGTH IS 10.0.'
      WRITE(12,*)'X AXIS EXISTENCE IS 1.'
      WRITE(12,755) PSTEP
  755 FORMAT(' X AXIS STEP SIZE IS ',F4.1,'.')
      WRITE(12,*)'X AXIS TICK MARKS IS 5.'
      WRITE(12,*)'X AXIS INTEGERIZE OFF.'
      WRITE(12,700)
  700 FORMAT(' ','X AXIS LABEL TEXT IS "FLUID INJECTED, CUM. PV".')
      WRITE(12,702) PMAX
  702 FORMAT(' ','X AXIS MIN IS 0.0, X AXIS MAX IS ',F3.1,'.')
      WRITE(12,*)'X AXIS ORIGIN IS 0.0.'
      WRITE(12,*)'Y AXIS EXISTENCE IS 1.'
      WRITE(12,*)'Y AXIS ORIGIN IS 3.75.'
      WRITE(12,704) INMAX
  704 FORMAT(' ','Y AXIS MIN IS 0.0, Y AXIS MAX IS ',I3,'.')
      WRITE(12,750) INSTEP
  750 FORMAT(' ','Y AXIS STEP SIZE IS ',I2,'.')
      WRITE(12,*)'Y AXIS TICK-MARKS IS 10.'
      WRITE(12,706)
  706 FORMAT(' ','Y AXIS LABEL TEXT IS "OIL RECOVERY, %HCPV".')
      WRITE(12,*)'INPUT DATA.'
      WRITE(12,*)'"HCPV"'
      WRITE(12,716) (RVPT(J3),PREC(J3),J3=1,N)
  716 FORMAT(F5.2,' ',F6.2)
      WRITE(12,*)'END OF DATA.'
      WRITE(12,*)'CURVE 1 COLOR RED.'
C
C  THIS SECTON IS FOR PLOTTING THE RECOVERY LABEL
C    - OX AND OY CONTAIN THE X AND Y VALUE IN COORDINATE
C      UNITS.
C    - OX1 AND OY1 ARE THE OX AND OY VALUE IN INCHES
C      (MEASURED FROM THE ORIGIN).
C     NOTE:IF THE LENGTH OF EITHER AXIS IS CHANGED THEN
C        THEY SHOULD BE ALTERED IN  THE OX1 AND THE OY1
C        EQUATIONS TO LINE UP THE MESSAGES ON THE GRAPHS.
C        PRESENTLY THE LENGTHS OF THE X AND THE Y AXIS
C        ARE 10.0 AND 7.0 RESPECTIVELY.
C    - OX2 AND OY2 ARE THE X AND Y POINTER LOCATION (INCHES).
C      THE NUMBERS, 1.2477 AND .26, ARE THE LENGTH OF THE
C      POINTER AND THE STUB RESPECTIVELY.
C
      IF(ANSWER.EQ.'N') GOTO 730
      RX1=(RX*10.0)/PMAX
      RY1=(RY*7.0)/FLOAT(INMAX)
      RX2=RX1-1.2477
      RY2=RY1+.26
C
C  MESSAGE 2 IS THE START OF THE POINTER.
C     MSG ARROW-HEAD > DEFINES THE TYPE OF ARROW-HEAD.
C     MSG CONNECT POINT > DEFINES THE LOCATION OF WHERE THE
C       POINTER IS TO EXTEND FROM (TC > TOP CENTER).
C     MSG POINTER > DEFINES THE LOCATION OF WHERE THE POINTER
C       SHOULD END.
C     MSG TEXT > DEFINES THE TEXT OF THE MESSAGE WHICH IS IN
C       THE QUOTES.
C     MSG UNITS > DEFINES THE UNITS WHICH ARE USED FOR MESSAGE
C       2. IN THIS CASE, PLOT INCHES, WILL PLOT IN INCHES
C       WITH THE ORIGIN OF THE GRAPH BEING THE POINT 0.0 0.0.
C     MSG X, Y > DEFINES THE LOCATION OF THE MESSAGE TEXT. THE
C       X AND Y ARE IN THE SAME UNITS WHICH ARE DEFINED IN
C       THE "MSG UNITS..." STATEMENT.
C  MESSAGE 3 CONTAINS THE LABEL OF THE CURVE.
C    NOTE: HERE THE MSG CONNECT POINT IS BR (BOTTOM RIGHT)
C        WHICH IS NOT THE SAME AS RB (RIGHT BOTTOM).
```

```
C     MSG X, Y > THE SAME AS THE ABOVE EXCEPT HERE IT IS OFF-
C       SET .04 INCHES IN THE Y DIRECTION.
C
      WRITE(12,*)'MESSAGE 2.'
      WRITE(12,*)'MSG ARROW-HEAD IS 1201.'
      WRITE(12,*)'MSG CONNECT POINT IS TC.'
      WRITE(12,718) RX2,RY2
  718 FORMAT(' ','MSG POINTER IS TC ',F6.4,' ',F6.4,'.')
      WRITE(12,*)'MSG TEXT IS " ".'
      WRITE(12,*)'MSG UNITS IS PLOT INCHES.'
      WRITE(12,719) RX1,RY1
  719 FORMAT(' ','MSG X IS ',F6.4,' , Y IS ',F6.4,'.')
      WRITE(12,*)'MESSAGE 3.'
      WRITE(12,*)'MSG CONNECT POINT IS BR.'
      WRITE(12,*)'MSG TEXT IS "RECOVERY".'
      WRITE(12,*)'MSG HEIGHT IS 0.15.'
      WRITE(12,*)'MSG UNITS IS PLOT INCHES.'
      WRITE(12,720) RX1,(RY2+.04)
  720 FORMAT(' ','MSG X IS ',F6.4,' , Y IS ',F6.4,'.')
C
  730 CONTINUE
      WRITE(12,*)'SUBPLOT 3.'
C
C THIS SECTION DRAWS THE OPFIR CURVE IN STEP MODE. EVEN THOUGH
C ONLY THE Y AXIS IS PLOTTED, THE X AXIS SPECIFICATION MUST BE
C INCLUDED TO PLOT THE CURVE.
C
      WRITE(12,*)'GENERATE A PLOT.'
      WRITE(12,*)'WINDOW DESTINATION IS 0.77 7.7 0.65 6.15.'
      WRITE(12,*)'X AXIS LENGTH IS 10.0.'
      WRITE(12,*)'X AXIS EXISTENCE IS 0.'
      WRITE(12,*)'X AXIS MODE IS REVERSED.'
      WRITE(12,801) PSTEP
  801 FORMAT(' X AXIS STEP SIZE IS ',F4.1,'.')
      WRITE(12,*)'X AXIS TICK MARKS IS 5.'
      WRITE(12,802) PMAX
  802 FORMAT(' ','X AXIS MIN IS 0.0, X AXIS MAX IS ',F3.1,'.')
      WRITE(12,*)'X AXIS ORIGIN IS 0.0.'
      WRITE(12,*)'Y AXIS EXISTENCE IS 1.'
      WRITE(12,*)'Y AXIS OFFSET IS 10.0.'
      WRITE(12,*)'Y AXIS MODE IS REVERSED.'
      WRITE(12,804) XOMAX
  804 FORMAT(' ','Y AXIS MIN IS 0.0, Y AXIS MAX IS ',F3.1,'.')
      WRITE(12,*)'Y AXIS TICK MARKS IS 10.'
      WRITE(12,850) XOSTEP
  850 FORMAT(' ','Y AXIS STEP SIZE IS ',F3.1,'.')
      WRITE(12,*)'Y AXIS ORIGIN IS 3.75.'
      WRITE(12,*)'Y AXIS INTEGERIZE OFF.'
      WRITE(12,*)'CURVE 1 STAIR, SYMBOL TYPE IS 0, THICKNESS=2.'
      WRITE(12,*)'CURVE 1 SHADE PATTERN 30140,SHADE TEXTURE'//
     1' SOLID.'
      WRITE(12,*)'CURVE 1 SHADE COLOR IS BLACK.'
      WRITE(12,*)'CURVE 1 SHADE PAIR IS -1.'
      WRITE(12,*)'Y AXIS LABEL TEXT"OIL PROD-FLUID INJ RATIO,'//
     1' sm3 / m3".'
      WRITE(12,*)'INPUT DATA.'
      WRITE(12,*)'"OPFIR"'
      WRITE(12,818) RVPT(1),ZERO
      DO 520 J4=1,N
      IF(OPFIR(J4).EQ.99.99) GOTO 821
      WRITE(12,818) RVPT(J4),OPFIR(J4)
  520 CONTINUE
  821 WRITE(12,818) RVPT(N),ZERO
  818 FORMAT(F4.2,' ',F5.3)
      WRITE(12,*)'END OF DATA.'
      WRITE(12,*)'CURVE 1 COLOR BLACK.'
      WRITE(12,*)'CURVE 1 SHADE PATTERN IS 30140.'
      WRITE(12,*)'CURVE 1 SHADE TEXTURE IS SOLID.'
C
C  MESSAGE 1 CONTAINS THE NOTE, THE FIGURE HEADING, AND THE
C  COMMENT WHICH ARE LOCATED BELOW THE PLOTS.
C     NTITLE CONTAINS THE COMMENT WHICH IS CENTERED ON A 72
C     COLUMN PAPER. THE COMMENT CAN BE MOVED LEFT OR RIGHT
C     BY ALTERING THE NUMBER (eg. 36) IN THE VARIABLE
C     "BLANK(:36-(IJ/2))". BY INCREASING THE NUMBER THE COMMENT
C     WILL SHIFT RIGHT, AND DECREASING THE NUMBER WILL SHIFT
C     THE COMMENT LEFT.
C
      WRITE(12,911) ARP,AFV,OVIS,PHI,KABS,SOI,SWC
  911 FORMAT(' ','MESSAGE 1',
     1'"NOTE:"',
     2'+" Average Run Conditions:"',/
     3'+" Direct Line Drive, "',/
     4'+"',F4.2,' MPa and 23<H.5E)O<HXEX)C",'/,
     5'"      Model Parameters: Average Flow "'/
     6,'+"Velocity = ',F5.3,' m/d,"'/,
     8' +" <M7)m<MXH.5L)O<HXLX) = ',F6.1,' mPa.s"'/,
     7'"      <M7)v<MX) = ',F5.2,' %, k = ',F6.3,'"'/
     9' +" darcies, "'/,
     1'+"S<H.5L)O<HXLX) = ',F5.2,' %, S<H.5L)"',/
     1'+"WC<HXLX) = ',F5.2,' %",')
      WRITE(12,502) TITLE,NRUN
  502 FORMAT(' ','"       "',/,'"',7X,A70,'",',/,'"      "',/
     I'"         Figure     -  Production',
     1' History of Run LC',I2,'.",',/
     1'ASCII CASE.')
      WRITE(12,*)'MSG 1 SPACE RATIO IS 1.5, HEIGHT IS .2.'
      WRITE(12,*)'MSG 1 CONNECT LB, X=.1,Y=0.0.'
      WRITE(12,*)'MSG 1 Y OFFSET IS 0.5.'
C
C  THIS SECTION IS FOR PLOTTING THE OPFIR LABEL
C     - OX AND OY CONTAIN THE X AND Y VALUE IN COORDINATE
C       UNITS.
C     - OX1 AND OY1 ARE THE OX AND OY VALUE IN INCHES
```

```
C      (MEASURED FROM THE ORIGIN).
C     NOTE:IF THE LENGTH OF EITHER AXIS IS CHANGED THEN
C        THEY SHOULD BE ALTERED IN  THE OX1 AND THE OY1
C        EQUATIONS TO LINE UP THE MESSAGES ON THE GRAPHS.
C        PRESENTLY THE LENGTHS OF THE X AND THE Y AXIS
C        ARE 10.0 AND 7.0 RESPECTIVELY.
C    - OX2 AND OY2 ARE THE X AND Y POINTER LOCATION (INCHES).
C      THE NUMBERS, 1.2477 AND .26, ARE THE LENGTH OF THE
C      POINTER AND THE STUB RESPECTIVELY.
C
      IF(ANSWER.EQ.'N') GOTO 830
      OX1=(OX*10.0)/PMAX
      OY1=(OY*7.0)/XOMAX
      OX2=OX1+1.2477
      OY2=OY1+.26
C
C  MESSAGE 2 IS THE START OF THE POINTER.
C     MSG ARROW-HEAD > DEFINES THE TYPE OF ARROW-HEAD.
C     MSG CONNECT POINT > DEFINES THE LOCATION OF WHERE THE
C       POINTER IS TO EXTEND FROM (TC > TOP CENTER).
C     MSG POINTEF > DEFINES THE LOCATION OF WHERE THE POINTER
C       SHOULD END.
C     MSG TEXT > DEFINES THE TEXT OF THE MESSAGE WHICH IS IN
C       THE QUOTES.
C     MSG UNITS > DEFINES THE UNITS WHICH ARE USED FOR MESSAGE
C       2. IN THIS CASE, PLOT INCHES, WILL PLOT IN INCHES
C       WITH THE ORIGIN OF THE GRAPH BEING THE POINT 0.0 0.0.
C     MSG X, Y > DEFINES THE LOCATION OF THE MESSAGE TEXT. THE
C       X AND Y ARE IN THE SAME UNITS WHICH ARE DEFINED IN
C       THE "MSG UNITS..." STATEMENT.
C  MESSAGE 3 CONTAINS THE LABEL OF THE CURVE.
C    NOTE: HERE THE MSG CONNECT POINT IS BL (BOTTOM LEFT)
C        WHICH IS NOT THE SAME AS LB (LEFT BOTTOM).
C     MSG X, Y > THE SAME AS THE ABOVE EXCEPT HERE IT IS OFF-
C       SET .04 INCHES IN THE Y DIRECTION.
C
      WRITE(12,*)'MESSAGE 2.'
      WRITE(12,*)'MSG ARROW-HEAD IS 1201.'
      WRITE(12,*)'MSG CONNECT POINT IS TC.'
      WRITE(12,822) OX2,OY2
  822 FORMAT(' ','MSG POINTER IS TC ',F6.4,' ',F6.4,'.')
      WRITE(12,*)'MSG TEXT IS " ".'
      WRITE(12,*)'MSG UNITS IS PLOT INCHES.'
      WRITE(12,823) OX1,OY1
  823 FORMAT(' ','MSG X IS ',F6.4,' , Y IS ',F6.4,'.')
      WRITE(12,*)'MESSAGE 3.'
      WRITE(12,*)'MSG CONNECT POINT IS BL.'
      WRITE(12,*)'MSG TEXT IS "  OPFIR".'
      WRITE(12,*)'MSG HEIGHT IS 0.15.'
      WRITE(12,*)'MSG UNITS IS PLOT INCHES.'
      WRITE(12,824) OX1,(OY2+.04)
  824 FORMAT(' ','MSG X IS ',F6.4,' , Y IS ',F6.4,'.')
```

```
C
  830 CONTINUE
      WRITE(12,*)'SUBPLOT 4.'
C
C  TO HAVE TELLAGRAF DRAW THE GRAPHS RIGHT AFTER PROCESSING
C  THEM, THE NEXT LINE SHOULD BE "WRITE(12,*)'DRAW 1 2 3 4.'".
C
      WRITE(12,*)'**FILE**'
      STOP
      END

C************************************************************
C*     SUBROUTINE STAR(RHO,PI,TEMP)                         *
C************************************************************
C
C PROGRAM STAR
C
C    THIS PROGRAM USES THE SECANT FUNCTION TO FIND
C   THE ROOT ("RHO") OF A FUNCTION ("X").
C   PRESSURE (IN MPag), TEMPERATURE (IN K), AND
C   INITIAL GUESSES FOR RHO (Kmol/m3).
C
C     X => THE EXTERNAL FUNCTION
C    RHO=> DENSITY
C     P => PRESSURE
C     T => TEMPERATURE
C
      EXTERNAL X
      COMMON P,T
      P=PI
      T=TEMP
C
C  PASSING THE FIRST TWO GUESSES TO THE FUNCTION.
C
      RHO1=0.5
      RHO2=1.0
      X1=X(RHO1)
      X2=X(RHO2)
C
C  SETTING UP THE DO-LOOP TO ITTERATE TO FIND THE
C  ROOT.
C
      DO 200 I=1,1000
       XD=X2-X1
       RHOD=RHO1-RHO2
C
C  CHECKS TO SEE IF THE FUNCTION HAS REACHED THE ROOT
C
      IF(ABS(X1).LE.1.0E-7) THEN
        RHO=RHO1
        RETURN
      ELSEIF(ABS(X2).LE.1.0E-7) THEN
```

```
        RHO=RHO2
        RETURN
      ENDIF
C
C  CHECKS TO SEE IF THE FUNCTION IS LESS THAN THE
C  TOLERANCE.
C
      IF(ABS(XD).LE.1.0E-6) GOTO 500
C
C   CHECKS TO SEE IF THE DIFFERENCE BETWEEN THE DENSITIES
C   IS LESS THAN THE TOLERANCE.
C
      IF(ABS(RHOD).LE.1.0E-5) GOTO 500
         RHO3=RHO2-X2*((RHO2-RHO1)/(X2-X1))
         X3=X(RHO3)
      IF(X2*X3.LT.0.0) THEN
         RHO1=RHO3
         X1=X3
       ELSE
         RHO2=RHO3
         X2=X3
       ENDIF
 200  CONTINUE
 500  RHO=RHO2
      RETURN
      END


C******************************************************
C*     FUNCTION X(RHO)                                *
C******************************************************
C STARLING FUNCTION
C
C     RHO => DENSITY OF CO2 IN Kmol/m3
C     P => PRESSURE IN MPag
C     T => TEMPERATURE IN K
C
      COMMON P,T
C
      DATA BO,AO,CO,DO,EO /0.024588,0.176976,2.451876E04,
     #1.883482E06,2.631556E04/
      DATA B,A,D,BETA /0.003781,0.009434,0.055761,0.0000961229
     #/
      DATA C,GAMMA,R /1.4197888E03,0.006421,0.008314/
C
       X=RHO*R*T+(BO*R*T-AO-CO/T**2+DO/T**3-EO/T**4)*RHO**2
     #+(B*R*T-A-D/T)*RHO**3+BETA*(A+D/T)*RHO**6+(C*RHO**3/T**2)
     #*(1+GAMMA*RHO**2)*EXP(-GAMMA*RHO**2)-P
      RETURN
      END
```

```
C************************************************************
C*     SUBROUTINE MAXX(MAX,ST,IMAX,IST)                       *
C************************************************************
C  THIS SUBROUTINE IS CALLED BY PROCESS2.FOR TO FIND THE
C  MAXIMUM VALUE AND STEP SIZE FOR EACH GRAPH.
C
C     MAX - MAXIMUM VALUE
C         - REAL FORMAT
C         - EQUAL TO 0.0 IF IMAX IS BEING USED
C     STEP- STEP SIZE FOR MAX
C         - EQUAL TO 0.0 IF MAX IS NOT BEING CALCULATED
C     IMAX- MAXIMUM VALUE
C         - INTEGER FORMAT
C         - EQUAL TO 0 IF MAX IS BEING USED
C    ISTEP- STEP SIZE FOR IMAX
C
      REAL MAX
      DIMENSION ISTEP(15),STEP(5)
      DATA ISTEP /2,5,10,15,20,25,30,35,40,45,50,55,100,200,300/
      DATA STEP /.1,.2,.4,.5,1.0/
      IF(IMAX.EQ.0.AND.MAX.EQ.0.0) THEN
       IMAX=10*(NINT(IMAX*.13+.5))
       IST=2
      ENDIF
      IF(IMAX.EQ.0) GOTO 45
      DO 10 I=1,15
      IF(IMAX.LE.10*ISTEP(I)) GOTO 20
   10 CONTINUE
   20 DO 30 J=1,10
      IF(IMAX.LE.J*ISTEP(I)) GOTO 40
   30 CONTINUE
   40 IMAX=J*ISTEP(I)
      IST=ISTEP(I)
      IF(MAX.EQ.0.0) RETURN
   45 DO 50 II=1,5
      XSTEP=FLOAT(NINT(100.0*STEP(II)))/10.0
      IF(MAX.LE.XSTEP) GOTO 60
   50 CONTINUE
   60 DO 70 JJ=1,10
      IF(MAX.LE.FLOAT(JJ)*STEP(II)) GOTO 80
   70 CONTINUE
   80 MAX=FLOAT(JJ)*STEP(II)
      ST=STEP(II)
      RETURN
      END
      PROGRAM MATBAL
C
C                                                     BY: STEVE DYER
C                                                     DATE: DEC/1988
C
C  THIS PROGRAM CALCULATES AND PLOTS THE MATERIAL BALANCE FOR
C  OIL, WATER, AND CARBON DIOXIDE GAS ON A PORE VOLUME BASIS.
C  DATA INPUT IS THE SAME AS THE MAIN DATA PROCESSING PROGRAM.
C  THE TELLAGRAF FILE FOR THE MATERIAL BALANCE PLOT IS PUT INTO
C  A FILE NAMED LC#.MAB. THE PURPOSE OF THE MATERIAL BALANCE
C  PROGRAM IS TO CHECK FOR EXPERIMENTAL ERROR IN THE EXPERIMENT.
C
      REAL MVA,NP,MV,NMOL,KABS,NPT,GPT,CDR,CDRT,CDRET
      REAL OPFIR,RVT,WPT,GPV,TVT
      LOGICAL USED
      CHARACTER*1 ANS,ANSC,ANSWER
      CHARACTER*10 FDDAT,FDMAB
      CHARACTER*66 BL
      CHARACTER*72 TITLE,BLANK,NTITLE
      DIMENSION VFI(50),RVP(50),PREC(50),GOR(50),WOR(50)
      DIMENSION OPFIR(50),MV(50),NMOL(50),CDRI(50),NP(50)
      DIMENSION PI(50),PP(50),BI(50),GI(50),BP(50),OP(50)
      DIMENSION GP(50),RVPT(50)
      DIMENSION WP(50),GV(50),GVOL(50),TV(50),TVOL(50)
      DATA BLANK /' '/
      DATA IGMAX,IWMAX,INMAX,XOMAX,PMAX /0,0,0,0.0,0.0/
      DATA IGSTEP,IWSTEP,INSTEP,XOSTEP,PSTEP /0,0,0,0.0,0.0/
      DATA ZERO /0.0/
C
C************************************************************
C*              DATA ENTRY                                  *
C************************************************************
C
C  ASKING THE USER FOR THE NAME OF THE DATA FILE WHICH MUST
C BE LESS THAN TEN CHARACTERS LONG:
C
    1 WRITE(*,*) 'ENTER THE NAME OF THE DATA FILE ('' '')'
      READ(*,*) FDDAT
C
C  TAKING THE FIRST PART OF THE DATA FILE NAME (UP TO THE
C  PERIOD), AND CREATING NEW NAMES FOR THE MATERIAL BALANCE
C  PLOT FILE.
C
C  FINDING THE END OF THE COMMENT. IJ WILL CONTAIN
C  THE NUMBER OF CHARACTERS IN THE COMMENT ('TITLE').
C
      DO 32 IK=1,10
      IF(FDDAT(IK:IK).EQ.'.') GOTO 31
   32 CONTINUE
   31  FDMAB=FDDAT(:IK)//'MAB'
C
C  OPENING AND READING THE DATA FILE.
```

```
C
      OPEN(UNIT=10,FILE=FDDAT,STATUS='OLD')
      READ(10,*) NTABLE,NRUN,NFIG
      READ(10,12) TITLE
   12 FORMAT(A72)
C
C  FINDING THE END OF THE COMMENT. IJ WILL CONTAIN
C  THE NUMBER OF CHARACTERS IN THE COMMENT ('TITLE').
C
      DO 14 IJ=0,72,2
      IF(TITLE(IJ:IJ+2).EQ.' ') GOTO 15
   14 CONTINUE
   15 READ(10,*) OVIS,PV,HCPV,PHI,SWC,SOI,KABS,MVA,TEMP
      READ(10,*) SSC,IWR,ARP,AFV
C
C    N CONTAINS THE NUMBER OF DATA POINTS
C
   50 READ (10,*) N
      DO 34 I=1,N
       READ(10,*) PI(I),PP(I),BI(I),GI(I),BP(I),OP(I),GP(I)
   34 CONTINUE
C
C************************************************************
C*              CALCULATION SECTION                         *
C************************************************************
C
C   INITIALIZING CONSTANTS
C
       NPT=0.0
       CDRT=0.0
       CDRET=0.0
       RVT=0.0
       WPT=0.0
       GPV=0.0
       TVT=0.0
       GMAX=0.0
       WMAX=0.0
       XOMAX=0.0
C
C  BEGINING THE CALCULATIONS USING THE DATA THAT WAS READ IN.
C  THIS SECTION ALSO CALLS "STAR" WHICH CONTAINS THE
C  THE STARLING EQUATION OF STATE. STAR UTILIZES THE
C  SECANT ROOT FINDING METHOD.
C
C  RVT, NPT, AND CDRT ARE TEMPORARY TOTALS FOR THE ARRAYS
C  RVPT,NP, AND CDRI RESPECTIVELY. THESE TEMPORARY VARIABLES
C  ARE NEEDED TO FIND THE TOTAL. TOTALS ARE FOUND BY ADDING
C  THE PREVIOUS
C  AND TO FIND,THE TOTAL THE PREVIOUS VALUE MUST BE ADDED
C  TO THE PRESENT TOTAL.
C     THE VARIABLES ENDING IN '-MAX' CONTAIN THE MAXIMUM
C  VALUE OF THE VARIABLE. THIS MAXIMUM WILL BE USED LATER
```

```
C  FOR THE TAG FILE.
C
      DO 200 I=1,N
      VFI(I)=BI(I)+GI(I)
      RVP(I)=VFI(I)/PV
      RVPT(I)=RVT+RVP(I)
      RVT=RVPT(I)
C
      NP(I)=NPT+(OP(I)/PV)
      NPT=NP(I)
C
      WP(I)=WPT+(BP(I)/PV)
      WPT=WP(I)
C
      CALL STAR(MV(I),PI(I),TEMP)
      NMOL(I)=GP(I)*MVA*1.0E-3
      GV(I)=(NMOL(I)/MV(I))*1.0E+06
      GVOL(I)=GPV+(GV(I)/PV)
      GPV=GVOL(I)
C
      TV(I)=NP(I)+WP(I)+GVOL(I)
C
  200 CONTINUE
C
      XNMAX=PREC(N)
      PMAX=RVPT(N)
C
C*************************************************************
C*             PLOTTING THE RESULTS                          *
C*************************************************************
C
C  OPENING AND READING THE TAG FILE WHICH WILL CONTAIN THE
C  NECESSARY COMMANDS FOR *TELLAGRAF TO PLOT THE GRAPHS.
C
  501 OPEN(UNIT=12,FILE=FDMAB,STATUS='NEW',IOSTAT=IERR)
C
C  CHECKING TO SEE IF THE FILE ALREADY EXISTS. IF IT DOES
C  THEN THE COMPUTER WILL ASK YOU FOR ANOTHER FILE NAME.
C
      IF(IERR.NE.0) THEN
      WRITE(*,*)' THIS FILE ALL READY EXISTS, PLEASE ENTER'//
     #' THE NAME OF A NON-EXISTING FILE.'
C
C  ASKING THE USER FOR THE NAME OF THE PLOT FILE WHICH MUST
C BE LESS THAN TEN CHARACTERS LONG.
C
      WRITE(*,*) 'ENTER THE NAME OF THE MAB FILE ('' '')'
      READ(*,*) FDMAB
      GOTO 501
      ENDIF
C
C NTITLE CONTAINS THE CENTERED COMMENT.
```

```
C
      NTITLE=BLANK(:40-(IJ/2))//TITLE(:IJ)
C
C     FINDING THE MAXIMUM POINT AND THE STEP SIZE BY
C     USING THE MAXX SUBROUTINE.
C     THE NUMBERS ARE PASSED:  REAL,REAL,INTEGER,INTEGER
C     IF THE NUMBERS ON THE AXIS ARE INTEGERS THE FORM
C     TO USE WOULD BE CALL MAXX(0.0,0.0,INTEGER,INTEGER).
C     IF THE NUMBERS ON THE AXIS ARE REAL THE FORM TO
C     USE WOULD BE CALL MAXX(REAL,REAL,0,0).
C
 1015 INMAX=10*NINT(XNMAX/10.0+0.5)
      IGMAX=10*NINT(GMAX/10.0+0.5)
      IWMAX=10*NINT(WMAX/10.0+0.5)
      CALL MAXX(0.0,0.0,IGMAX,IGSTEP)
      CALL MAXX(0.0,0.0,IWMAX,IWSTEP)
      CALL MAXX(0.0,0.0,INMAX,INSTEP)
      CALL MAXX(XOMAX,XOSTEP,0,0)
      CALL MAXX(PMAX,PSTEP,0,0)
      PMAX=FLOAT(NINT(PMAX*5.5+.5))/5.0
C
C THIS SECTION DRAWS THE FOUR CURVES. BOTH THE X AXIS AND
C THE Y AXIS ARE PLOTTED.
C
      WRITE(12,*)'GENERATE A PLOT.'
      WRITE(12,*)'X AXIS LENGTH IS 8.0.'
      WRITE(12,*)'X AXIS EXISTENCE IS ON.'
      WRITE(12,*)'X AXIS TICK MARKS IS 4.'
      WRITE(12,550) PSTEP
  550 FORMAT(' ',' X AXIS STEP SIZE IS ',F3.1,'.')
      WRITE(12,*)'X AXIS INTEGERIZE OFF.'
      WRITE(12,503) PMAX
  503 FORMAT(' ','X AXIS MIN IS 0.0, X AXIS MAX IS ',F4.1,'.')
      WRITE(12,*)'X AXIS ORIGIN IS 1.5.'
      WRITE(12,*)'Y AXIS ORIGIN IS 2.5.'
      WRITE(12,*)'Y AXIS EXISTENCE IS ON.'
      WRITE(12,*)'Y AXIS LENGTH IS 4.3.'
      WRITE(12,*)'Y AXIS INTEGERIZE OFF.'
      WRITE(12,504) PMAX
  504 FORMAT(' ','Y AXIS MIN IS 0, Y AXIS MAX IS ',F4.1,'.')
      WRITE(12,551) PSTEP
  551 FORMAT(' ','Y AXIS STEP SIZE IS ',F3.1,'.')
      WRITE(12,*)'Y AXIS TICK-MARKS IS 4.'
      WRITE(12,506)
  506 FORMAT(' ','Y AXIS LABEL TEXT" Produced CO2, Oil, Water',
     +' [Cum. PV]".')
      WRITE(12,*)'Y AXIS HEIGHT IS 0.12.'
      WRITE(12,719)
  719 FORMAT(' ','X AXIS LABEL TEXT" Fluid Injected',
     +' [Cum. PV]".')
      WRITE(12,*)'X AXIS HEIGHT IS 0.12.'
C
```

```
      WRITE(12,*)'INPUT DATA.'
C
      WRITE(12,*)'"CO2 Gas"'
      WRITE(12,*)'0.0 0.0'
      WRITE(12,512) (RVPT(J1),GVOL(J1),J1=1,N-1)
C
      WRITE(12,*)'"Oil"'
      WRITE(12,*)'0.0 0.0'
      WRITE(12,512) (RVPT(J2),NP(J2),J2=1,N-1)
C
      WRITE(12,*)'"Water"'
      WRITE(12,*)'0.0 0.0'
      WRITE(12,512) (RVPT(J3),WP(J3),J3=1,N-1)
C
      WRITE(12,*)'"Total [CO2+Oil+H2O]"'
      WRITE(12,*)'0.0 0.0'
      WRITE(12,512) (RVPT(J4),TV(J4),J4=1,N-1)
C
      WRITE(12,*)'"Ideal Material Balance"'
      WRITE(12,*)'0.0 0.0'
      WRITE(12,512)PMAX,PMAX
C
  512 FORMAT(2(F7.5,' '))
C
      WRITE(12,*)'END OF DATA.'
C
      WRITE(12,*)'CURVE 1 TEXTURE IS CHAINDASHED, COLOR IS RED.'
      WRITE(12,*)'CURVE 1 SYMBOL TYPE 1, SIZE 1, COUNT IS 2.'
      WRITE(12,*)'CURVE 1 SMOOTH, DELTA IS 0.10.'
C
      WRITE(12,*)'CURVE 2 TEXTURE IS DASHED, COLOR IS BLACK.'
      WRITE(12,*)'CURVE 2 SYMBOL TYPE 2, SIZE 1, COUNT IS 2.'
      WRITE(12,*)'CURVE 2 SMOOTH, DELTA IS 0.10.'
C
      WRITE(12,*)'CURVE 3 TEXTURE IS 7, COLOR IS RED.'
      WRITE(12,*)'CURVE 3 SYMBOL TYPE 18, SIZE 1, COUNT IS 2.'
      WRITE(12,*)'CURVE 3 SMOOTH, DELTA IS 0.10.'
C
      WRITE(12,*)'CURVE 4 TEXTURE IS SOLID, COLOR IS BLACK.'
      WRITE(12,*)'CURVE 4 SYMBOL TYPE 17, SIZE 1, COUNT IS 2.'
      WRITE(12,*)'CURVE 4 SMOOTH, DELTA IS 0.10.'
C
      WRITE(12,*)'CURVE 5 TEXTURE IS DOTTED, COLOR IS RED.'
      WRITE(12,*)'CURVE 5 SMOOTH, DELTA IS 0.1.'
      WRITE(12,*)'CURVE 5 SYMBOL TYPE 3,SIZE 1,COUNT IS 9999.'
C
      WRITE(12,*)'LEGEND EXISTENCE IS ON.'
      WRITE(12,*)'LEGEND TEXT IS " ".'
      WRITE(12,*)'LEGEND UNITS IS INCHES.'
      WRITE(12,*)'LEGEND CONNECT IS LB.'
      WRITE(12,*)'LEGEND BOX IS 2.0 5.5 4.7 6.5.'
      WRITE(12,*)'LEGEND FRAME IS ON.'
      WRITE(12,*)'LEGEND FRAME COLOR IS BLACK.'
      WRITE(12,*)'LEGEND HEIGHT IS 0.3.'
C
      WRITE(12,*)'FRAME THE PLOT.'
      WRITE(12,*)'FRAME COLOR IS BLACK.'
C
      WRITE(12,*)'SUBPLOT 1.'
C
      WRITE(12,*)'GENERATE A PLOT.'
      WRITE(12,*)'X AXIS LENGTH IS 8.0.'
      WRITE(12,*)'X AXIS EXISTENCE IS OFF.'
      WRITE(12,*)'X AXIS TICK MARKS IS 4.'
      WRITE(12,650) PSTEP
  650 FORMAT(' ',' X AXIS STEP SIZE IS ',F3.1,'.')
      WRITE(12,*)'X AXIS INTEGERIZE OFF.'
      WRITE(12,603) PMAX
  603 FORMAT(' ','X AXIS MIN IS 0.0, X AXIS MAX IS ',F4.1,'.')
      WRITE(12,*)'X AXIS ORIGIN IS 1.5.'
      WRITE(12,*)'Y AXIS ORIGIN IS 2.5.'
      WRITE(12,*)'Y AXIS EXISTENCE IS OFF.'
      WRITE(12,*)'Y AXIS LENGTH IS 4.3.'
      WRITE(12,651) PSTEP
  651 FORMAT(' ','Y AXIS STEP SIZE IS ',F3.1,'.')
      WRITE(12,*)'Y AXIS TICK-MARKS IS 4.'
      WRITE(12,*)'Y AXIS INTEGERIZE OFF.'
      WRITE(12,604) PMAX
  604 FORMAT(' ','Y AXIS MIN IS 0, Y AXIS MAX IS ',F4.1,'.')
      WRITE(12,606)
  606 FORMAT(' ','Y AXIS LABEL TEXT" ".')
      WRITE(12,819)
  819 FORMAT(' ','X AXIS LABEL TEXT" ".')
C
      WRITE(12,*)'LEGEND EXISTENCE IS OFF.'
      WRITE(12,*)'INPUT DATA.'
C
      WRITE(12,*)'"CO2 Gas"'
      WRITE(12,612) (RVPT(K1),GVOL(K1),K1=N-1,N)
C
      WRITE(12,*)'"Oil"'
      WRITE(12,612) (RVPT(K2),NP(K2),K2=N-1,N)
C
      WRITE(12,*)'"Water"'
      WRITE(12,612) (RVPT(K3),WP(K3),K3=N-1,N)
C
      WRITE(12,*)'"Total [CO2+Oil+H2O]"'
      WRITE(12,612) (RVPT(K4),TV(K4),K4=N-1,N)
C
C
  612 FORMAT(2(F7.5,' '))
C
      WRITE(12,*)'END OF DATA.'
C
```

```
      WRITE(12,*)'CURVE 1 TEXTURE IS CHAINDASHED, COLOR IS RED.'
      WRITE(12,*)'CURVE 1 SYMBOL TYPE 1, SIZE 1, COUNT IS 1.'
      WRITE(12,*)'CURVE 1 SMOOTH, DELTA IS 0.10.'
C
      WRITE(12,*)'CURVE 2 TEXTURE IS DASHED, COLOR IS BLACK.'
      WRITE(12,*)'CURVE 2 SYMBOL TYPE 2, SIZE 1, COUNT IS 1.'
      WRITE(12,*)'CURVE 2 SMOOTH, DELTA IS 0.10.'
C
      WRITE(12,*)'CURVE 3 TEXTURE IS 7, COLOR IS RED.'
      WRITE(12,*)'CURVE 3 SYMBOL TYPE 18, SIZE 1, COUNT IS 1.'
      WRITE(12,*)'CURVE 3 SMOOTH, DELTA IS 0.10.'
C
      WRITE(12,*)'CURVE 4 TEXTURE IS SOLID, COLOR IS BLACK.'
      WRITE(12,*)'CURVE 4 SYMBOL TYPE 17, SIZE 1, COUNT IS 1.'
      WRITE(12,*)'CURVE 4 SMOOTH, DELTA IS 0.10.'
C
C  MESSAGE 1 CONTAINS THE NOTE, THE FIGURE HEADING, AND THE
C  COMMENT WHICH ARE LOCATED BELOW THE PLOTS.
C     NTITLE CONTAINS THE COMMENT WHICH IS CENTERED ON A 72
C     COLUMN PAPER. THE COMMENT CAN BE MOVED LEFT OR RIGHT
C     BY ALTERING THE NUMBER (eg. 36) IN THE VARIABLE
C     "BLANK(:36-(IJ/2))". BY INCREASING THE NUMBER THE COMMENT
C     WILL SHIFT RIGHT, AND DECREASING THE NUMBER WILL SHIFT
C     THE COMMENT LEFT.
C
      WRITE(12,911) ARP,AFV,OVIS,PHI,KABS,SOI,SWC
  911 FORMAT(' ','MESSAGE 1',
     1'"NOTE:"',
     2'+" Average Run Conditions:"',/
     3'+" Direct Line Drive, "',/
     4'+"',F4.2,' MPa and 23<H.5E)O<HXEX)C",'/,
     5'"      Model Parameters: Average Flow "'/
     6,'+"Velocity = ',F5.3,' m/d,"'/,
     8' +" <M7)m<MXH.5L)O<HXLX) = ',F6.1,' mPa.s"'/,
     7'"      <M7)v<MX) = ',F5.2,' %, k = ',F6.3,'"'/
     9' +" darcies, "'/,
     1'+"S<H.5L)O<HXLX) = ',F5.2,' %, S<H.5L)"',/
     1'+"WC<HXLX) = ',F5.2,' %",')
      WRITE(12,900) TITLE,NRUN
  900 FORMAT(' ','"        "',/,'"',7X,A70,'",',/,'"     "',/
     1'"         Figure          -  Volumetric ',
     1'Balance on Run LC',I2,'.",',/
     1'ASCII CASE.')
      WRITE(12,*)'MSG 1 BOX IS 2.5 9.0 0.2 1.50.'
      WRITE(12,*)'MSG 1 SPACE RATIO IS 1.2, HEIGHT IS .25.'
      WRITE(12,*)'MSG 1 CONNECT LB, X=.1,Y=0.0.'
      WRITE(12,*)'MSG 1 Y OFFSET IS 0.5.'
C
      WRITE(12,*)'SUBPLOT 2.'
      WRITE(12,*)'**FILE**'
      STOP
      END
      PROGRAM BAR
C
C                                                    BY: Steve Dyer
C                                                    Date: Dec/88
C
C THIS PROGRAM DRAWS A BAR /PIE CHART OF THE OIL THAT IS
C RECOVERED FROM THE MODEL. THE PROGRAM READS THE
C SAME DATA FILES AS THE PROCESS2.FOR PROGRAM, AND
C CREATS A TAG FILE (LC##.BAR) WHICH WILL BE USED
C BY TELLAGRAF.
C
      CHARACTER*10 FNAME,PNAME
      CHARACTER*72 TITLE,BLANK,NTITLE
      REAL MVA,KABS
C
C THE ASKS THE USER FOR THE DATA FILE NAME AND
C THEN OPEN THE FILE.
C
      WRITE(*,*)'ENTER THE DATA FILE'
      READ(*,*) FNAME
      OPEN(UNIT=10,FILE=FNAME,STATUS='OLD')
C
C ONLY THE FIRST FOUR LINES ARE READ FROM THE DATA
C FILE.
C
      READ(10,*) NTABLE,NRUN
      READ(10,'(A72)') TITLE
      DO 5 IJ=0,72,2
      IF(TITLE(IJ:IJ+2).EQ.' ') GOTO 6
    5 CONTINUE
    6 READ(10,*) OVIS,PV,HCPV,PHI,SWC,SOI,KABS,MVA,TEMP
      READ(10,*) SSC,IWR,ARP,AFV
      DO 7 IK=1,10
      IF(FNAME(IK:IK).EQ.'.') GOTO 8
    7 CONTINUE
C
C OPENING A TAG FILE WITH A STATUS OF 'NEW'.
C
    8 PNAME=FNAME(:IK)//'BAR'
      OPEN(UNIT=11,FILE=PNAME,STATUS='NEW')
C
C CREATING THE TAG FILE.
C
      WRITE(11,*)'GENERATE A LABELED VERTICAL FANCY BAR.'
      WRITE(11,*)'X PAGE IS 8.5.'
      WRITE(11,*)'Y PAGE IS 11.'
      WRITE(11,*)'X AXIS LENGTH IS 5.4.'
      WRITE(11,*)'Y AXIS LENGTH IS 6.9.'
      WRITE(11,*)'X AXIS ORIGIN IS 2.20.'
      WRITE(11,*)'Y AXIS ORIGIN IS 2.80.'
      WRITE(11,*)'X AXIS HEIGHT IS 0.10.'
      WRITE(11,*)'Y AXIS HEIGHT IS 0.12.'
      WRITE(11,*)'Y AXIS STEP SIZE IS 5.'
      WRITE(11,*)'Y AXIS TICK MARKS IS 5.'
      WRITE(11,*)'X AXIS LABEL TEXT IS "Slug Order".'
      WRITE(11,*)'Y AXIS LABEL TEXT IS "Oil Recovery, %HCPV".'
      WRITE(11,*)'X AXIS DIVISION LABELS IS "1st" "2nd" "3rd" '
      WRITE(11,*)'"4th" "5th" "6th" "7th" "8th" "9th" "10th" '
      WRITE(11,*)'"PWF" "BD".'
      WRITE(11,*)'BAR GAP IS 50.'
C
      WRITE(*,*)' ','ENTER MAX SLUG RECOVERY (CO2+H2O)+ 10.0(/5)'
      READ(*,*)VORPT
      WRITE(11,10)VORPT
   10 FORMAT(' ','Y AXIS MAX IS ',F5.2,'.')
C
      WRITE(11,*)'INPUT DATA.'
C
      WRITE(11,*)'"CO2 [WAG]"'
      WRITE(*,11)
   11 FORMAT(' ','ENTER THE 10 GAS SLUG RECOVERIES (%) ')
      READ(*,*)A,B,C,D,E,F,G,H,O,P
      WRITE(11,12)A,B,C,D,E,F,G
   12 FORMAT(' ','1,',F5.2,' 2,',F5.2,' 3,',F5.2,' 4,',F5.2,
     +' 5,',F5.2,' 6,',F5.2,' 7,',F5.2)
      WRITE(11,13)H,O,P
   13 FORMAT(' ',' 8,',F5.2,' 9,',F5.2,' 10,',F5.2)
      WRITE(11,*)'11,0.0 12,0.0'
C
      WRITE(11,*)'"Brine [WAG]"'
      WRITE(*,14)
   14 FORMAT(' ','ENTER THE 10 WATER SLUG RECOVERIES (%) ')
      READ(*,*)A1,B1,C1,D1,E1,F1,G1,H1,O1,P1
      WRITE(11,15)A1,B1,C1,D1,E1,F1,G1
   15 FORMAT(' ','1,',F5.2,' 2,',F5.2,' 3,',F5.2,' 4,',F5.2,
     +' 5,',F5.2,' 6,',F5.2,' 7,',F5.2)
      WRITE(11,16)H1,O1,P1
   16 FORMAT(' ',' 8,',F5.2,' 9,',F5.2,' 10,',F5.2)
      WRITE(11,*)'11,0.0 12,0.0'
C
      WRITE(11,*)'"Post Waterflood [PWF]"'
      WRITE(11,*)'1,0.0 2,0.0 3,0.0 4,0.0 5,0.0 6,0.0 7,0.0'
      WRITE(11,*)'8,0.0 9,0.0 10,0.0'
      WRITE(*,17)
   17 FORMAT(' ','ENTER THE POST WATERFLOOD RECOVERY (%) ')
      READ(*,*)PWF
      WRITE(11,18)PWF
   18 FORMAT(' ','11,',F5.2)
      WRITE(11,*)'12,0.0'
C
      WRITE(11,*)'"Blowdown [BD]"'
      WRITE(11,*)'1,0.0 2,0.0 3,0.0 4,0.0 5,0.0 6,0.0 7,0.0'
      WRITE(11,*)'8,0.0 9,0.0 10,0.0 11,0.0'
      WRITE(*,19)
   19 FORMAT(' ','ENTER THE BLOWDOWN RECOVERY (%) ')
      READ(*,*)BD
      WRITE(11,20)BD
   20 FORMAT(' ','12,',F5.2)
C
      WRITE(11,*)'END OF DATA.'
C
      WRITE(11,*)'STACKED.'
C
      WRITE(11,*)'DIST 2 DOC PLACEMENT IS EXTERNAL.'
      WRITE(11,*)'DIST 2 DOC ALPHA IS STANDARD.'
      WRITE(11,*)'DIST 2 DOC ANGLE IS 90.'
      WRITE(11,*)'DIST 2 DOC CONNECT IS TC.'
      WRITE(11,*)'DIST 2 DOC IS TIP VALUE.'
      WRITE(11,*)'DIST 2 DOC PRECISION IS 4.'
      WRITE(11,*)'DIST 2 DOC SUFFIX IS "%".'
      WRITE(11,*)'DIST 2 DOC HEIGHT IS 0.10.'
      WRITE(11,*)'DIST 3 DOC PLACEMENT IS EXTERNAL.'
      WRITE(11,*)'DIST 3 DOC ALPHA IS STANDARD.'
      WRITE(11,*)'DIST 3 DOC ANGLE IS 90.'
      WRITE(11,*)'DIST 3 DOC CONNECT IS TC.'
      WRITE(11,*)'DIST 3 DOC IS TIP VALUE.'
      WRITE(11,*)'DIST 3 DOC PRECISION IS 4.'
      WRITE(11,*)'DIST 3 DOC SUFFIX IS "%".'
      WRITE(11,*)'DIST 3 DOC HEIGHT IS 0.10.'
      WRITE(11,*)'DIST 4 DOC PLACEMENT IS EXTERNAL.'
      WRITE(11,*)'DIST 4 DOC ALPHA IS STANDARD.'
      WRITE(11,*)'DIST 4 DOC ANGLE IS 90.'
      WRITE(11,*)'DIST 4 DOC CONNECT IS TC.'
      WRITE(11,*)'DIST 4 DOC IS TIP VALUE.'
      WRITE(11,*)'DIST 4 DOC PRECISION IS 4.'
      WRITE(11,*)'DIST 4 DOC SUFFIX IS "%".'
      WRITE(11,*)'DIST 4 DOC HEIGHT IS 0.10.'
C
      WRITE(11,*)'DIST 1 SHADE PATTERN IS 135240,COLOR IS RED.'
      WRITE(11,*)'DIST 2 SHADE PATTERN IS 45240,COLOR IS BLACK.'
      WRITE(11,*)'DIST 3 SHADE PATTERN IS 0,COLOR IS BLACK.'
      WRITE(11,*)'DIST 4 SHADE PATTERN IS 90110,COLOR IS RED.'
C
      WRITE(11,*)'FRAME THE PLOT.'
      WRITE(11,*)'FRAME COLOR IS BLACK.'
C
      WRITE(11,*)'LEGEND FRAME IS ON.'
      WRITE(11,*)'LEGEND BOX IS 3.5 5.5 8.25 9.5.'
      WRITE(11,*)'LEGEND HEIGHT IS 0.11.'
C
      WRITE(11,*)'INCH GRID OFF.'
      WRITE(11,*)'SUBPLOT 1.'
C
      WRITE(11,*)'GENERATE A FANCY PIE.'
      WRITE(11,*)'DIVISION-LABEL IS "WAG" "PWF" "BD" "UREC".'
      WRITE(11,*)'INPUT DATA.'
      WRITE(*,21)
   21 FORMAT(' ','ENTER TOTAL WAG RECOVERY (%) ')
      READ(*,*)WAG
C
      UREC=100.00-WAG-PWF-BD
C
      WRITE(11,22)WAG,PWF,BD,UREC
   22 FORMAT(' ','1,',F5.2,' 2,',F5.2,' 3,',F5.2,' 4,',F5.2)
      WRITE(11,*)'END OF DATA.'
C
      WRITE(11,*)'PIE HEIGHT IS 0.075.'
      WRITE(11,*)'ANNOTATION PLACEMENT IS INTERNAL.'
      WRITE(11,*)'ANNOTATION BLANKING IS ON.'
      WRITE(11,*)'ANNOTATION DATA EXISTENCE IS OFF.'
      WRITE(11,*)'ANNOTATION PERCENT EXISTENCE IS OFF.'
      WRITE(11,*)'ANNOTATION TEXT EXISTENCE IS ON.'
      WRITE(11,*)'ANNOTATION FRAME IS ON.'
      WRITE(11,*)'PIE UNITS IS INCHES.'
      WRITE(11,*)'PIE X CENTER IS 4.75.'
      WRITE(11,*)'PIE Y CENTER IS 6.875.'
      WRITE(11,*)'PIE RADIUS IS 1.0.'
      WRITE(11,*)'LEGEND IS NO.'
C
      WRITE(11,*)'SLICE 1 SHADE PATTERN IS 45241, COLOR IS RED.'
      WRITE(11,*)'SLICE 2 SHADE PATTERN IS 0, COLOR IS BLACK.'
      WRITE(11,*)'SLICE 3 SHADE PATTERN IS 90110, COLOR IS RED.'
      WRITE(11,*)'SLICE 4 SHADE PATTERN IS 70450, COLOR IS BLACK.'
C
C
C  MESSAGE 1 CONTAINS THE NOTE, THE FIGURE HEADING, AND THE
C  COMMENT WHICH ARE LOCATED BELOW THE PLOTS.
C     NTITLE CONTAINS THE COMMENT WHICH IS CENTERED ON A 72
C     COLUMN PAPER. THE COMMENT CAN BE MOVED LEFT OR RIGHT
C     BY ALTERING THE NUMBER (eg. 36) IN THE VARIABLE
C     "BLANK(:36-(IJ/2))". BY INCREASING THE NUMBER THE COMMENT
C     WILL SHIFT RIGHT, AND DECREASING THE NUMBER WILL SHIFT
C     THE COMMENT LEFT.
C
      WRITE(11,23) ARP,AFV,OVIS,PHI,KABS,SOI,SWC
   23 FORMAT(' ','MESSAGE 1',
     1'"NOTE:"',
     2'+" Average Run Conditions:"',/
     3'+" Direct Line Drive, "',/
     4'+"',F4.2,' MPa and 23<H.5E)O<HXEX)C",'/,
     5'"      Model Parameters: Average Flow "'/
     6,'+"Velocity = ',F5.3,' m/d,"'/,
     8' +" <M7)m<MXH.5L)O<HXLX) = ',F6.1,' mPa.s"'/,
     7'"       <M7)v<MX) = ',F5.2,' %, k = ',F6.3,'"'/
     9' +" darcies, "'/,
     1'+"S<H.5L)O<HXLX) = ',F5.2,' %, S<H.5L)"',/
     1'+"WC<HXLX) = ',F5.2,' %",')
      WRITE(11,24) TITLE,NRUN
   24 FORMAT(' ','"       "',/,'"',7X,A70,'"',/,'"    "',/
     1'"         Figure    -  Oil Recovery ',
     1'Distribution of Run LC',I2,'."',/
     1'ASCII CASE.')
      WRITE(11,*)'MSG 1 BOX IS 2 7.5 0.5 2.'
      WRITE(11,*)'MSG 1 SPACE RATIO IS 1.5, HEIGHT IS .2.'
      WRITE(11,*)'MSG 1 CONNECT LB, X=.1,Y=0.0.'
      WRITE(11,*)'MSG 1 Y OFFSET IS 0.5.'
      WRITE(11,*)'SUBPLOT 2.'
C
      WRITE(11,*)'**FILE**'
      STOP
      END
```

Appendix E

Detailed Laboratory Procedures

1.0 Oil Preparation

1.1 Original Water Content

a) Transfer a 50 ml sample of oil in a 100 ml stoppered graduated cylinder.
b) Add approximately 20 ml of toluene, stopper the graduated cylinder and shake vigorously.
c) Pour the sample into a 100 ml centrifuge tube.
d) Rinse the graduated cylinder with toluene and add contents to a 100 ml centrifuge tube. Continue rinsing until no oil remains in the graduated cylinder.
e) Repeat the above procedure with another 50 ml sample.
f) Place centrifuge tubes opposite from each other in the centrifuge.
g) Close cover and spin for approximately 15 minutes.
h) The % water content = 2.0 times the volume of water read at the bottom of each of the centrifuge tubes.
i) Water content must be less than 1.0%.

1.2 Water Separation

~ If water content is greater than 1.0%, it must be separated from the oil.
~ Make sure oil dryer is free of any previous oil samples, ie: empty but not necessarily clean.

1.2.1 Gravity Separation

a) Add approximately 30 litres (6.5 gal.) of oil to the flanged opening of the dryer, and bolt up flange. Total mass of oil must be known.
b) Let stand for approximately 7-10 days.
c) With a container under the bottom spout, open the valve slowly and drain off as much water as possible until a constant stream of oil appears, then close the valve.
d) After draining the water, turn on the rotator for several hours to mix the oil thoroughly.
e) Turn the rotator off and repeat test 1.1 above for original water content.
f) If no water was extracted immediately, or the water content is still greater than 1.0% the sample must be heat separated.

1.2.2 Heat Separation

a) The cooling apparatus must first be turned on and run for approximately 24 hours before the heat separation process may be started.
b) Dry ice must be placed around the condenser collector tube in the bucket during this time.
c) All connections should be sealed with vacuum grease to prevent any vacuum leaks in the apparatus.
d) Turn on the heating pads around the dryer. The oil should not be heated above 40.0 °C, check the thermometer at the front of the dryer periodically.
e) After the cooling apparatus has run for 1 day, the heat separation process is ready to proceed. Make sure the bucket is full of ice.
f) Bolt flange down and turn the rotator and the vacuum pump on.
g) Check the vacuum gauge, it should read approximately 27 inches of vacuum, if not check for leaks throughout the system.
h) Run for 2-3 days, checking the vacuum gauge and dry ice twice daily.
i) Turn the heat, vacuum and rotator off.
j) Drain water from both collectors (in bucket & external) and collect the light oils in a separate graduated cylinder.
k) Remove flange and add the light oils to the dryer.
l) Replace flange and rotate the mixture for several hours, with heat and vacuum **off**.
m) Stop the rotation and let the sample settle and cool down for a short period of time.
n) Repeat test 1.1 above for original water content. If water content is still greater than 1.0% go to section 1.2.3 Emulsion Breaker/Heat Separation .

1.2.3 Emulsion Breaker/Heat Separation

a) Add several **drops** of emulsion breaker to the dryer. **Caution**: do not add too much emulsion breaker.
b) Replace flange and repeat steps 1.2.2 Heat separation.
c) If there are no immediate results add a few more **drops** of emulsion breaker.

~ If the water content is still greater than 1.0% after section 1.2.3, then something is wrong with the oil sample or the previous procedures have not been carried out properly or, for a long enough period of time.

1.3 Oil Viscosity

~ Oil viscosity is measured at 23°C with the Brookfield digital rotating viscometer.

1.3.1 Bath Preparation

a) Obtain a sample of oil, approximately 900 ml, from the dryer in a 1000 ml beaker.
b) Place the beaker in the Exacal temperature bath making sure not to splash any water into the oil sample.
c) Fill the bath with distilled water until the level is above the oil level or the bath is full. **Caution**: do not splash water into the oil sample..
d) Connect either of the hoses from the back of the temperature bath to the sink spout and place the other end in the sink near the drain.
e) Turn on the **cold** water as well as the bath heater.
f) Adjust bath temperature with fine controller until bath temp is exactly 23 °C (read thermometer).
g) With a separate thermometer stir the oil sample and read the temp in the center of the beaker.
h) Repeat f) - g) until oil temperature is exactly 23 °C.

1.3.2 Viscosity Measurement

~ Oil viscosity is measured at 23 °C.

a) Place the Brookfield viscometer around the corner of the bath and directly over the oil sample, plug in and check to see that it is leveled.
b) Attach spindle #3 to the viscometer and turn the power on.
c) Adjust readout until a 0.00 reading is constant.
d) Slowly lower the spindle into the center of the oil sample until the oil level is half-way up the notch on the spindle arm.
e) Set the speed dial to position #6 and turn motor on.
f) Record the readout every minute for 6-10 minutes ie: reading should be constant after a few minutes.
g) Set speed to positions #12, 30; 60 and repeat step f) for each speed.
h) Calculate the arithmetic average reading at each speed and use this value to calculate the viscosity (RPM slide card speed factors) at each speed. The lower RPM sometimes produce results which deviate significantly from the higher RPM results, if this is the case ignore lower RPM results.
i) Arithmetically average the viscosities calculated above, multiply this result by the viscometer correction factor [CF] determined using Dow-Corning viscosity fluids. **CF = 1.02897103**
j) Record final viscosity, measured at 23 °C, in mPa•s.

~ Final viscosity of the oil, at 23 °C, should be between 1030-1060 mPa•s for mixed Aberfeldy oil.

1.3.3 Oil Viscosity Too High

a) Pour 900 ml oil sample back into the dryer.
b) Add commercial light oil to the dryer, bolt flange down and rotate for several hours to mix the new sample.
c) Repeat sections 1.3.1 and 1.3.2 until desired oil viscosity is reached.

1.3.4 Oil Viscosity Too Low

a) Pour 900 ml oil sample back into the dryer.
b) Add heavy oil to the dryer, bolt flange down and rotate for several hours to mix the new sample.
c) Repeat sections 1.3.1 and 1.3.2 until desired oil viscosity is reached.

1.3.5 Mass Calculations for Addition of Light/Heavy Oil

a) Mass of oil in the dryer should be known approximately ie: it will have changed slightly due to the removal of the water as well as some of the oil.
b) Calculation of mass of light or heavy oil to be added as needed is as follows:

L = total mass of light oil
H = total mass of heavy oil
μ_t = oil viscosity of mixture
a = mass of light/heavy to be added for a specific μ_t

$$\frac{1}{\mu_T} = \frac{H/(H+L)}{\mu_H} + \frac{L/(H+L)}{\mu_L}$$

Where (H+L) = the total mass of the mixture at the present measurement stage.

Example: Present mass of heavy oil = 1500.0 g μ_H=1195.6mPa•s
Present mass of light oil = 0.0 g μ_L = 290.0 mPa•s
Present viscosity = 1090 mPa•s
Required viscosity = 1040 mPa•s

1040/CF = 1040/1.02897103 = 1010.7184 mPa•s (H+L) = 1500.0+0.0 = 1500.0

$$\frac{1.0}{1010.7184} = \frac{\{1500 / (1500+a)\}}{1195.6} + \frac{\{a / (1500+a)\}}{290.0}$$

$$\frac{(1195.6)(290.0)}{1010.7184} = \frac{(290.0)(1500) + (1195.6)a}{(1500 + a)}$$

$$\frac{(1500 + a)}{\{(290)(1500) / 1195.6\} + a} = \frac{1195.6}{\{(290)(1195.6) / 1010.7184\}}$$

a = 93.33 g of light oil to be added.

2.0 Linear Core

2.1 Bulk Volume Determination

~ The bulk volume of the linear core should be measured before the packing procedure is carried out for each run to ensure the accuracy of further calculations.

~ Potentially the linear core may have a slightly different bulk volume and therefore, porosity for each run.

2.1.1 Installation of Chevron

~ The first chevron is installed on the **opposite** end of the core with the scribe marks, ie: the production end.

a) Lower the production chevron into the core until it is resting firmly on the bottom of the machined surface.
b) Install the external collar, by rotating clockwise, until it is snug against the chevron. Next, install the chevron outer ring along with the six hex bolts.
c) Begin to tighten up the hex bolts in a cross-wise sequence. Initially this will pull the chevron up slightly which is compensated by rotating the external collar a small amount. Continue this until the chevron and external collar are completely snug sealing one end of the core.

2.1.2 Dimensional Determination

~ Lines are inscribed 1/8th of an inch and approx. 5/8ths of an inch above the bottom of the machined surface at the injection end of the core. This will ensure that all runs have approximately the same bulk volume.

~ One end of the core should be sealed at this time ie: see section 2.1.1

a) Inside diameter [D] is 9.78 cm.
b) The length [L] is slightly variable and therefore it must be measured before each run. The length is measured from the bottom screen to the top of the scribe line 5/8ths of an inch above the machined surface.
c) Bulk Volume [BV] = $\{\pi/4.0\} \bullet D^2 \bullet L$ [cm^3]

2.1.3 Volumetric Determination

~ Corrections must be made for the volume contained in the chevrons as well as all of the fittings.

~ One end of the core should be sealed at this time ie: see section 2.1.1

~ Results should be compared with the dimensional determination.

~ The volumetric method is more accurate than the dimensional method.

~ Water refers to tap water.

a) With the production end of the core sealed, the core should be inverted so that the injection end is facing up.

b) Open the bottom valve and begin to add water into the open end of the core. When the water begins to flow out the bottom, close the valve. At this point there should be a small level of water in the core, if not add some.

c) Slowly open the valve while watching the level of water inside the core. When the water level sinks so that it is just below the screen, close the valve.

d) At this point the chevron and all fittings are completely full of water. Now with **known** volumes of water fill the core up to the top of the upper scribe mark.

e) The volume of water added is the bulk volume of the core.

f) This may be verified by measuring the volume drained from the core by opening the bottom valve and draining the water into a number of large graduated cylinders. You must watch the level of water inside the core and close the valve when the water level sinks so that it is just below the screen as in step c).

g) This procedure should be repeated several times so that an accurate average of the bulk volume is measured.

h) Invert the core vertically so the open side is facing down, and remove the production valve. Attach the high pressure air line to the q/c.

i) Turn the high pressure air on and blow air through the chevron and core to dry it out before packing.

2.2 Core Preparation and Packing

~ Bulk volume must be known before the core may be packed.

~ One end of the core must be completely sealed at this stage.

2.2.1 Dry Packing

a) Invert the core so that the open end is up and that it is perfectly leveled. Check with level gauge.

b) Place the chain clamp around the core above the stand clamps to prevent the core from sliding down during the vibration.

c) The threads at the top of the core must be protected from any sand particles that may get trapped in the threads and subsequently damage them. This is accomplished by wrapping parafilm around the threads and sealing the top with tape. Be sure no threads are exposed.

d) Attach the vibrator to the side of the core, approximately half-way, using the anchor bolts and the angle iron.

e) Connect the vacuum apparatus, through the regulator, to the vibrator. Begin to vibrate the core by opening the regulator fully.

f) Begin to fill the core with the Ottawa silica sand. Do not add in large amounts at one time.

g) Fill to a level just below the very top of the core. Open the high pressure air line and begin to vibrate the core. Check the sand level in approximately one-half hour to see if the sand level has dropped, if so add a small amount to bring the level back up.

h) When the level of sand remains constant, back the pressure off with the regulator until the pressure reads **200 kPa**. Vibrate the core for approximately 7-10 hours.

i) Turn vibrator off and begin to remove the extraneous sand above the scribe mark. When enough sand has been removed so that the scribe mark is visible turn the vibrator back on and add sand as needed so that the sand level just covers the scribe mark.

j) The core is now ready to be sealed at the open end. Be careful not to disturb the sand pack until the injection chevron is in place.

k) Clean off all excess sand and lower the chevron in slowly until it is resting firmly on the sand pack. **Caution**: do not get any sand in/on the threads.

l) Turn the vibrator on for 5-10 minutes so that the chevron face will be firmly against the sand pack.

m) Turn the vibrator off, remove the parafilm, and install the external collar and hex bolts as described in section 2.1.1 .

n) Be sure the collar and hex bolts are all tight and then remove the vibrator and chain clamp.

~ The core is now ready for pore volume and permeability determination.

~ Modifications may have to be made if the "head" of sand above the scribe mark during the packing process is not large enough to give consistent results. This can be tested by using a larger head of sand in the next run, ie: by using some sort of extension collar, and comparing the pore volumes obtained in each run. If the pore volumes are significantly different, then a collar will have to be implemented in step f) of the packing procedure.

2.2.2 Wet Packing

~ The wet packing procedure may have to be used if the dry packing procedure gives inconsistent results.

~ The wet packing procedure is a simple modification of the dry packing procedure.
~ Pore volume determination is carried out in a completely different fashion if wet packing is utilized, see section 4.2.3.

a) Position the core vertically with open end up, and add approximately 1000 ml of distilled water into the core.
b) Turn the vibrator on and begin to add the Ottawa silica sand slowly.
c) The wet packing procedure requires that a 10 cm head of water is maintained above the sand pack at all times. This will require the use of an extension above the core.
d) When the level of sand reaches the 5/8^{ths} inch scribe mark, stop adding sand and vibrate the core for approximately one hour.
e) Remove the head of water on the top with a siphon and remove the extension.
f) Lower the chevron in slowly until it is resting firmly on top of the sand pack.
g) Remove the parafilm around the threads and install the external collar and hex bolts as described earlier.
h) Dismantle the vibrator and the chain clamp.

2.3 Pore Volume Determination

~ The pore volume for each run should be very similar so that comparative results between runs may be justified.
~ The term "brine" refers to the reservoir water in the white pails from Husky Oil.

2.3.1 Volume of Chevron's and Fittings

~ The volume of the fittings along with the chevrons should be determined between the two female quick-connects [q/c]. =40 cm^3

2.3.2 Pore Volume Procedure

a) With the core in the vertical position, connect the vacuum apparatus to the top of the core using the q/c fittings. Label this end "PROD".
b) Make sure that the system is closed at the bottom ie: q/c only. Label this end "INJ".
c) Turn the vacuum apparatus on and run for 6-10 hours.
d) After the vacuum has been applied, remove the q/c line, then shut the vacuum pump off.
e) Fill a 2000 ml graduated cylinder with exactly 2000 ml of brine and place below the inverted core close to the injection q/c.
f) Fill the plastic tubing(male q/c on one end) with brine, using the syringe, and lower into the graduated cylinder.

g) With the system closed at the top (PROD), **quickly** connect the q/c to the INJ end.

h) The brine will be drawn up into the core due to the vacuum present. Leave the bottom connected until the fluid level in the graduated cylinder remains constant. This will probably take 35-45 minutes, see Figure E2-1.

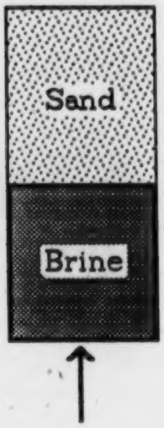


Figure E2-1. Linear Core Model Pore Volume Determination

i) The pore volume is the volume of brine drawn into the sand pack minus the volume of brine contained in the top and bottom fittings and chevrons, determined earlier.

~ The core is now ready to be pressure tested and to have the absolute permeability determined.

2.4 Permeability Determination

~ The model should be pressure tested at this stage to ensure that the system is completely sealed.
~ The linear core in the horizontal position represents a direct line drive situation with one producer and one injector.
~ Both of the following procedures require the vacuum apparatus.

2.4.1 Pressure Testing

~ The pressure test is conducted to ensure that the system is leak-proof before any experiment is carried out.

a) The cylinder on the L.H.S. of the vacuum apparatus [VA] must first be filled with brine by vacuuming it from a source of brine located below the VA. The vacuum line is connected to the top, through a vacuum flask, to the vacuum pump.

b) Continue vacuuming brine until it appears in the vacuum flask, this ensures that no air is in the system.
c) Connect the bottom of the cylinder with the steel braided q/c line to the injection end of the core. This line must first be filled with brine ie: bleed air out.
d) Connect the high pressure air supply line to the "building air" connection on the VA. Then connect the "regulator air" to the top of the cylinder on the L.H.S. of the VA.
e) Make sure the dial is set to "air" and be sure that all lines have been bled of any air.
f) Slowly begin to increase the pressure in the model by rotating the regulator control clockwise, be sure the production end is closed.
g) Set the regulator so that a pressure of approximately 600 kPa is showing on the gauge.
h) Watch the pressure gauge closely for a period of time to make sure that the pressure is not slowly dropping. Also visually inspect the model for any noticeable leaks.
i) If the pressure remains constant and no leaks are detected, the core is ready for the permeability determination.

2.4.2 Permeability Procedure

~ The permeability is measured by applying a pressure differential [ΔP] across the core, in the horizontal position, and measuring the subsequent flow rate [q], see Figure E2-2.

a) The pressure from the pressure test must first be released. This is accomplished by turning the regulator counter-clockwise until a small pressure is read on the gauge.
b) Connect a small plastic tube to the production valve of the core and pointing into a drain pail.
c) The pressure differential is applied across the model using the pressure regulator.
d) Open the production valve and rotate the regulator to set a ΔP across the core. Wait a while for the pressure transients to subside and thus having a constant pressure across the core.

Brine and Sand

Figure E2-2. Linear Core Model Permeability Determination

e) Measure the flow rate by obtaining a known volume of produced brine over a one or two minute period ie: may want a 2 minute period for low ΔP. Record the ΔP and q for each.

f) Repeat steps d) - e) for several different ΔP's remembering to let the pressure become constant before measuring the flow rate. Vary the ΔP between 5 and 50 kPa.

g) The absolute permeability [K] is calculated as follows:

$$K = \{ q \bullet \mu \bullet L \} / \{ A \bullet \Delta P \}$$

h) The values of K are arithmetically averaged out over the entire range of ΔP's unless some of them, especially at low ΔP, contradict the others, in this case these contradictory values should be ignored.

~ If we convert for the appropriate units and substitute for the cross-sectional area, then the absolute permeability [K] is calculated as follows:

$$K = 22.48008 \times 10^{-3} \bullet \{q \bullet \mu_t \bullet L\} / \Delta P$$

Where:
K = Absolute Permeability [Darcies]
q = Flow Rate [cc/min]
μ_t = Oil Viscosity [mPa•s]
L = Length of Core [cm]
ΔP = Pressure Differential Across Core [kPa]

~ If a consistent set of results are obtained, then the permeability determination is complete.

~ Air in the core may give erratic results, if this occurs the air must be bled from the system.

2.5 Oil Saturation of Core

~ Stable displacement of water by oil, of a lesser density, requires the oil be injected in the top and water be produced from the bottom.

2.5.1 Saturation Procedure

a) Connect the long glass cylinder containing crude oil to the Milroyal pump. The oil cylinder should be filled with oil of a known viscosity.

b) Open the stopcock on the oil cylinder and turn pump on to circulate the oil throughout the pump and its tubing.

c) Position the core in the vertical position so that the injection end is on top. Make sure the core is exactly vertical, see Figure E2-3.

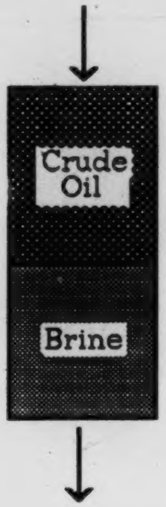


Figure E2-3. Linear Core Model Oil Saturation

d) The line joining the pump with the injector must first be filled with oil ie: bled of any air. Connect the line to the injection apparatus of the 2-D model. With the other end of the line open, turn on the pump until oil appears at the q/c end of the line ie: use dummy female q/c.

e) Turn the pump off and connect the line to the injection valve, making sure the valve has first been closed. At this stage all further oil pumped will be injected into the model. It is Imperative at this point to add oil to the oil cylinder and record the level it reads at in the glass cylinder.

f) Connect the small production tubing to the production valve and place a 1000 ml graduated cylinder below the production tubing.

g) Set capacity of Milroyal pump to a maximum of 7.0%. Turn the Milroyal pump on and open the injection and production valves.

h) Continue this process until the first drop of oil appears at the production end. **Caution**: The level of oil in the glass cylinder must be periodically checked and refilled. To refill the cylinder the process must be stopped, the present level recorded, add oil, record the new level, and then restart the process. The graduated cylinders, at the production end, must also be changed as they become filled and the total volume of fluids collected should be recorded immediately.

i) When the first drop of oil appears the 1000 ml graduated cylinder should be changed immediately to a smaller one, approximately 250 ml.

j) The smaller graduated cylinders should be changed often and the contents tested for %water content.

k) When the %water content is near that of the original water content (see step 1.1) then the core is fully saturated with oil. With the volume of brine produced known at this stage, the core pressure must now be brought up to the experimental pressure by injecting oil into the core while the production valves are closed.

l) Record the additional volume of oil required to raise the core pressure to the experimental pressure.

m) Close the injection valve to maintain the core at the experimental pressure.

2.5.2 Saturation Determination

~ Oil saturation determination is very important for further analysis of results of each run.
~ Initially the core is saturated 100% with brine.
~ Oil saturation is given the symbol: S_o
~ Oil saturation at the experimental pressure is given by the symbol: S_{om}
~ Connate water saturation is given the symbol: S_{wc}
~ Hydrocarbon pore volume is given the symbol: HCPV

a) A rough estimate of the oil saturation is made using the volume of oil injected.

$$S_o = \frac{[\text{Oil Injected-Oil Produced- Oil in Chevrons \& Fittings}]}{\text{Pore Volume} \quad [cm^3]}$$

S_{om} = Numerator + Additional Volume of Oil Required to Raise Pressure

b) A more accurate estimate of oil saturation is made using the volume of brine produced. Initially the core is assumed to be 100% saturated with brine therefore occupying all of the pore space. The volume of oil in the model is equal to the volume of water displaced.

$$S_o = \frac{[\text{ Volume Brine Produced-Oil in Chevrons \& Fittings}]\ [cm^3]}{\text{Pore Volume} \quad [cm^3]}$$

S_{om} = Numerator + Additional Volume of Oil Required to Raise Pressure

S_{wc} = 1.0 - S_o

$$= \frac{[\text{Pore Volume-Brine Produced+Oil in Chevrons \& Fittings}]}{\text{Pore Volume } [cm^3]}$$

~ The second calculation for connate water saturation is used to check the validity of the first calculation.
~ The volume of brine /oil produced is determined by separating the effluents in the centrifuge.

HCPV = S_{om} • Pore Volume [cm^3]

2.6 Data Acquisition and Coreflood Apparatus

2.6.1 Data Acquisition

~ All existing equipment already in place will be utilized for the linear core model.
~ Both the injector and producer each have separate Heise Pressure gauges and pressures are also recorded simultaneously on a Hybrid recorder.
~ Production pressure is controlled by a Back Pressure Regulator [BPR].
~ Liquids are collected in graduated cylinders and produced gas is measured with a Dry Test Meter [DTM].

2.6.2 Coreflood Apparatus

~ This equipment set-up incorporates all existing filters, regulators, valves and gauges for gathering data as well as all the experimental procedures.

a) Place core, in stand, facing the 2-D model, the production end should be on the R.H.S .
b) Rotate the core so that it is in the horizontal position and lock in place with a C-clamp. Check with the level gauge.
c) Join both ends of the model with the tubing provided, to the respective positions. Be sure the tubing already in place has been cleaned.

~ The model is now ready for the experimental procedure.
~ Fluid loss must be kept to an absolute minimum due to the small volumes encountered in the experiment.
~ Check all fittings and connections and make sure they are all snug.

3.0 Linear Core Experimental Procedures

3.1 Brineflood Setup

~ Brine flooding is only carried out on the initial runs so that CO_2 recovery may be compared to conventional methods on a relative basis.

~ The brine to be used in all runs is that which was supplied by Husky Oil and can be found in the five gallon white pails.

~ The initial oil saturation must be known before any type of displacement is carried out on the model.

a) The brine will be pumped from the constant rate pumps at the next highest rate nearest to the scaled rate calculated on the data sheet.

b) All lines must first be flushed of all other fluids which may be present, this is accomplished by pumping first Varsol, and then distilled water throughout the tubing system.

c) Once all of the lines have been cleaned, the brine should be circulated throughout the system.

d) The constant rate pump must then be filled with brine by closing all the external valves and redirecting the brine from the Milroyal pump into the constant rate pump.

e) After the constant rate pump is full, the valves should be redirected into the core with the injection valve nearest the core **closed.**

3.1.1 Brineflood Procedure

a) The lines must first be flushed with the brine from the pump, this is done by opening the bleed side of the 3-way valve at the top of the 2-D model and cranking the constant rate pump by hand until a clear stream of brine is seen.

b) The injection line must now be bled at the core. This is accomplished by redirecting the flow to the bleed side of the 3-way valve. When a clear stream of brine appears, turn the valve to the **off** position.

c) The injection lines must now be pressured to the same pressure that exists in the core. This is done by cranking the constant rate pump by hand and engaging it at a pressure near or below the experimental pressure.

d) The pump may then be turned on in short intervals to raise the pressure in the line to the desired experimental pressure.

e) When the pressure in the injection lines are near the experimental pressure open the injection valve nearest the core. If the pressures in the lines and in the core are approximately the same, the injection pressure gauge will only move slightly. If the injection pressure gauge moves dramatically, either the core or the injection lines are not pressured correctly and must be brought up to the experimental pressure.

3.1.2 Brineflood Run

a) Record the initial "reading" on the constant rate brine pump (2-decimals), the DTM (3-decimals), as well as the initial production and injection pressures.
b) Install a 100 ml graduated cylinder to collect the effluent. Initially only oil will be produced. Continue using 100 ml graduated cylinders until brine breakthrough occurs, then use 250 ml graduated cylinders.
c) Turn the constant rate pump on, making sure the CO_2 pump is disengaged, and open both production valves. The Back Pressure Regulator [BPR] should initially be set approximately half-way.
d) Initially the production pressure will have to be monitored frequently and adjusted accordingly, with the BPR, to the experimental pressure. This will usually take a few re-adjustments.
e) Record, with each change of cylinder, all values required on the data sheet. Before stopping the pump, the production and injection pressures should be recorded. As soon as the pump is turned off the production valve nearest the BPR should be turned off. Reverse the order after the graduated cylinder has been changed.
f) Before the pump has reached its maximum (≈490 cm^3) it must be refilled (see step 3.1 b).
g) Continue injecting brine until a producing WOR of approximately 20:1 has been reached. At this point the experiment is complete.

3.2 CO_2 WAG Process

~ This is the main process used in displacing heavy oil with CO_2
~ The WAG ratio may be varied
~ The WAG process is usually followed with a brine flood until a 20:1 WOR has been reached

3.2.1 Preliminary Calculations

a) HCPV = S_{om} • Pore Volume [cm^3]
b) Total CO_2 Volume @ EXP Conditions = 0.20 x HCPV [cm^3]
c) Total CO_2 Volume @ Meter Conditions =

$$0.20 \times HCPV \times \frac{MD^{*} \text{ @ EXP Conditions}}{0.416480 \times 10^{-4} \text{ [mol/cm}^3\text{]}}$$

d) Total Brine Volume = WAG Ratio x Total CO_2 Volume @ EXP Con.
e) Divide volume of CO_2 and Brine into 10 slugs each.

~ Molar Density* [mol/cm^3] - calculated using the Starling Equation of State.

3.2.2 WAG Procedure

~ The first slug in the WAG process is CO_2
~ Both the gas and brine constant rate pumps should be full before preceding with the experiment.
~ Again all lines should first be flushed with Varsol and then distilled water.

a) The injection lines must first be pressured to the core pressure. This is done by cranking the constant rate gas pump by hand, with the inlet valve closed, until the pressure is slightly above the experimental pressure.
b) Because the gas compresses so much, only a small volume of gas may be left in the pump after the experimental pressure is reached. If this is the case, the pump will have to be filled again before the run may proceed. This is done by closing the exit valve at the pump, disengaging, and opening the fill valve connected to the carbon dioxide tank.
c) Remember to reverse the procedure after the pump is full.
d) Record the initial "reading" on the constant rate pump (2-decimals), the DTM (3-decimals), as well as the initial production and injection pressures. Set the stopper on the pump approximately 5.0 cm^3 before the desired slug size volume.
e) See step 3.1.2 b). Set the rate on the pumps (see pump chart at back).
f) Turn the CO_2 constant rate pump on making sure the brine pump is disengaged, and open both production valves.
g) See steps 3.1.2 d) - f) .
h) When the pump shuts off due to the stopper turn it back on again by disengaging the stopper and pushing the restart button. Record the injection and production pressures and shut pump off manually at the desired slug size.
i) Close the production valve nearest the BPR as well as the injection valve nearest the core. Record the final "reading" as well as the DTM for produced gas. Close the main gas valve at the 2-D model, disengage the CO_2 pump, and partially release the pressure by cranking the pump counterclock-wise. The model is now ready for a brine slug.
j) Turn the main gas valve towards the brine injection line.
k) See steps 3.1.1 a) - e) and steps 3.1.2 a) - e) .
l) Remember to set the stopper on the brine pump approximately 5.0 cm^3 before the desired slug size volume.

~ At this point the procedure is altered back to the gas slug until 10 slugs of gas and 10 slugs of brine have been injected.

~ Continue injecting brine until a producing WOR of approximately 20:1 has been reached.

3.2.3 Blowdown Recovery

~ Blowdown recovery procedures take place after a producing WOR of approximately 20:1 has been reached.
~ Blowdown recovery is due to the pressure release in the model when gradually opened to atmospheric conditions.

a) Install a 250 ml graduated cylinder to collect the blowdown effluents and record the reading on the DTM.
b) Close the injection valve nearest the core.
c) With the production valves open, slowly begin to open the BPR (counterclock-wise) in small increments and let the pressure subside.
d) After the pressure has subsided, open the BPR another small increment.
e) Repeat steps c) - d) until the production pressure has been reduced to approximately 0.2 MPa. At this point, open the BPR fully and let the model stand for approximately 5 hours.
f) Blow out the remaining fluids in the production line into the last graduated cylinder with the high pressure air line. Note: first close valve nearest DTM.
g) Record the final reading on the DTM and perform the analysis on the blowdown effluents.

~ At this point the experiment is complete.

3.3 Cleanup Procedures

~ Do not begin the cleanup procedures until all of the effluents have been analyzed and recorded.
~ Cleanup is extremely important to all subsequent runs.
~ Core pressure is released during blowdown recovery.

3.3.1 Core Cleaning

a) Close both the production and injection valves nearest the core and disconnect the q/c's from both sides of the core.
b) Invert the core to the vertical position and move it away from the 2-D model.
c) Remove four of the six hex bolts, from the top chevron, leaving the remaining two opposite each other.
d) Loosen the remaining two hex bolts to release the pressure on the expanded teflon rings. Install the dummy male q/c.
e) Begin to remove the external collar by rotating counterclock-wise. The chain clamp may have to be used for leverage if the collar is too tight.

f) Continue removing the external collar. The two hex bolts in place will draw the chevron out with the removal of the collar.
g) Remove the external collar, along with the chevron, from the core.
h) Tie an open garbage bag to the open end of the core and invert the core 180° so that the open end is facing downwards into the garbage bag.
i) The sand pack must now be removed from inside of the core. This is done by connecting the air line to the top chevron and applying air pressure.
j) Continue blowing air into the core until the sand pack falls into the garbage bag. Remove the garbage bag immediately and tie it up.
k) Place a large open pail below the core and spray the inside walls down with Varsol until clean.
l) Place an air line inside the core and blow air through until the core is dry and free of any sand particles.

3.3.2 Chevron Cleaning

~ Do **not** use toluene or acetone when cleaning the chevrons, only use Varsol.

a) Remove the collars and teflon rings from the chevron body.
b) Spray the face and body of the chevron with Varsol to remove any sand particles and oil.
c) Insert the dummy male q/c to the chevron so that Varsol may flow through.
d) Spray Varsol through the chevron, in both directions, until a clear stream of Varsol is seen.
e) Connect an air line to the chevron and blow air through until the chevron is dry, approximately one-half hour.
f) Wipe the chevron collars and teflon rings clean and install back on the chevron body.
g) Repeat steps a) - d) for the other chevron.

3.3.3 Tubing Cleaning

~ Flush disconnected lines with toluene and acetone and blow air through immediately afterwards to dry.
~ Clean all other lines by pumping Varsol through followed by distilled water.
~ **Remember** to close valves nearest the Heise gauges before cleaning.

4.0 Gas Injection Systems

~ Several possibilities exist as to how gas may be injected into either model. The method used depends on the pressure at which the experiment is to be operated.

4.1 High Pressure Runs (> 5.50 MPa)

~ For high pressure runs in either model, the constant rate pump may be used. At high pressures (> 5.50 MPa) carbon dioxide behaves as a liquid and the volumes recorded from the constant rate pump are accurate. The procedure is the same as that described in section 3.2.2 .

4.2 Low Pressure Runs (< 5.50 MPa)

~ For low pressure runs a completely different system must be used for injecting carbon dioxide. Due to the phase behavior of carbon dioxide at low pressures (< 5.50 MPa) the actual gas volume must be measured. The modified system which has been implemented is the Matheson Metering System.

The Matheson Metering System (MMS) controls the rate at which carbon dioxide is being injected as well as measuring the volume which has been injected. The MMS measures both the rate and volume at standard conditions (70 °F and 1 atm).

Because the MMS measures the rate and volume at standard conditions, conversions must be made to adjust for experimental conditions. The following calculations must be made:

a) volume or number of moles injected per slug at experimental conditions;
b) rate of injection at experimental conditions;
c) volume injected per slug at meter conditions, and
d) rate of injection at meter conditions.

4.2.1 Gas Calculations

a) Vol(MMS) = Vol[Exp Cond] x { MV @ Exp Cond / MV @ MMS }
= Volume read on Matheson Totalizer (scm^3)

b) Rate(MMS) = {Rate[Exp Cond]/60} x {MV @ Exp Cond/MV @ MMS }
= Rate set on Matheson Dynablender (scm^3 / min)

MV @ MMS = 0.416480 x 10^{-4} (mol / cm^3)
MV @ 1.00 MPa = 0.433430 x 10^{-3} (mol / cm^3)
MV @ 2.50 MPa = 0.120426 x 10^{-2} (mol / cm^3)
MV @ 5.50 MPa = 0.385938 x 10^{-2} (mol / cm^3)

4.2.2 Modified Gas Injection System Procedure

a) Turn Matheson electrical components on and warm up for approximately one-half hour.
b) Open tank to regulator, with regulator initially set to zero ie: backed-off completely.
c) Set Control Valve to "FULL OPEN" on the Matheson Dynablender.

d) Slowly increase the pressure in the lines with the tank regulator until the desired experimental pressure is 'seen' on the Heise Pressure Gauge.
e) When the pressure differential gauge reads approximately zero, switch to "CONTROL" and "SET" on the Matheson Dynablender. The digital readout is the % maximum scale of the flow meter. ie: for a 100 scm^3/min flow meter, a reading of 1.0 corresponds to 10 scm^3/min.
f) Switch the Matheson Dynablender to "READ" and direct the flow of gas into the model while turning on the Totalizer simultaneously.
g) A pressure differential must exist across the MMS for flow to occur. If the rate shown on the dynablender is negative then increase the pressure slightly by **slowly** turning the tank regulator clockwise until a differential is 'seen' on the pressure differential gauge.
h) Monitor the flow rate and the pressure differential constantly.

4.2.3 Limitations of the MMS

~ The micrometer needle valve is used to make small adjustments in the pressure differential across the MMS by acting as a BPR.

a) Maximum Operating Pressure = 5/3 x 500 psi = 830 psi (5.75 MPa)
b) Maximum Pressure Differential across the MMS = 5.0 psid = 138 inches of water

5.0 Two Dimensional Model

~ This model was designed and built by Rojas and Farouq Ali.
~ The model was designed to meet particular scaling criterion as derived by Rojas.
~ The model is scaled from the Aberfeldy Field in southern Saskatchewan.

5.1 Model Preparation and Packing

~ Preparation and packing of the 2-D model varies significantly from that of the linear core and is much more time consuming.

5.1.1 Dry Packing

~ Dry packing is rarely applied to the 2-D model due to the shape and size of the cavity.

a) Invert the model so the open cavity is facing up.
b) Mount the vibrator on to the upper flange using the two large C-clamps.
c) Connect the pneumatic (ie: air operated) vibrator to the air line using the q/c, and turn vibrator on.

d) Fill the V-shaped trough on the aluminium pan with sand and gently place the pan over the open cavity making sure the bent lip is inside the cavity.
e) Slowly lift the back of the pan until sand begins to be vibrated out of the trough and into the cavity. Continue lifting the pack of the pan slowly until all of the sand has been deposited into the cavity then remove the pan.
f) Let the sand vibrate for approximately 5-10 minutes.
g) Repeat steps d) - f) until the sand level is flush with the top of the cavity. Let the model vibrate, while full of sand, for approximately 5 - 6 hours.
h) Disconnect the air line and remove the vibrator from the model.
i) Scrape the excess sand from the top of the cavity and remove all sand particles from the flange face. **Caution**: it is extremely important to remove all sand and dirt from the flange face if a proper seal is to be achieved.
j) Make sure the groove in the flange cover is free of all sand and dirt.
k) Apply a thin film of vacuum grease to the rubber sealing ring and insert the ring into the groove on the flange cover.
l) Slowly lower the flange cover onto the model guided by the cavity lip. **Caution**: make sure the sealing ring does not dislodge itself from the groove while installing the flange cover.
m) Bolt the flange firmly in place following the cross-wise sequence as shown in Figure E5-1.

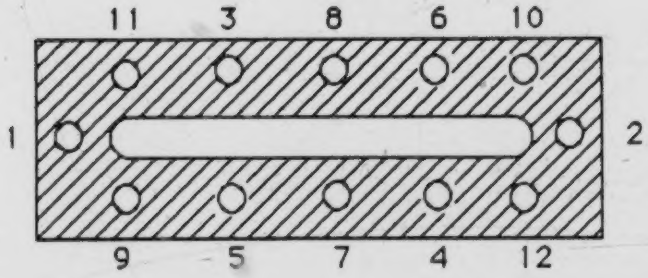


Figure E5-1. 2-D Model Flange Tightening Sequence

Caution: when following the sequence, do not over tighten each bolt too much, make several passes, tightening the bolts a little more with each pass.

n) With the flange cover now firmly in place, remove the "dummy" injection wells and install the perforated wells and accompanying injection "tree".
o) The model is now prepared for the pore volume determination.

5.1.2 Wet Packing

~ This is the most common method utilized when packing the 2-D model.
~ This method is very accurate but time consuming.

a) Invert the model so that the open cavity is facing up.
b) Insert the rubber sealing ring in the groove of the aluminium flange cover ie: flange with the 10 cm extended wall.
c) Install the aluminium flange cover onto the model using several bolts.
d) Mount the pneumatic vibrator on the aluminium flange cover using the two large C-clamps.
e) Connect the vibrator to the high pressure air line, use q/c, and turn vibrator on.
f) Fill the cavity with 10 cm of distilled water, ie: use the 10 cm marking stick.
g) See steps 4.1.1 d) - g). Between fillings of sand, check the height of distilled water above the sand pack, it should be kept at a constant 10 cm by adding distilled water when appropriate, see Figure E5-2.
h) Let the pack vibrate for approximately 10 - 15 minutes between sand fillings.
i) Repeat steps g) - h) until sand level is flush with top of the model and the aluminium cavity is full of distilled water.
j) Vibrate the model for approximately 10 - 12 hours, and periodically check the distilled water level.
k) Turn vibrator off and siphon the water from the aluminium cavity and remove the vibrator and the aluminium flange.
l) Install the flange cover, see steps 4.1.1 i) - o).
m) The model is now ready for the pore volume determination.

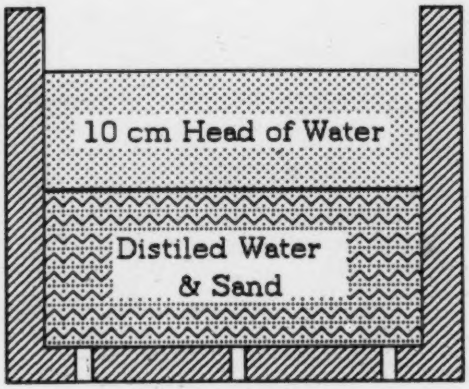


Figure E5-2. 2-D Model Pore Volume Displacement

5.2 Pore Volume Determination

~ The pore volume procedure is unique to the type of packing procedure used.

5.2.1 Dry Pack Procedure

a) Rotate the model so that the flange side is facing down and the injection tree is at the top.
b) The cavity must first be completely evacuated. This is accomplished by connecting the vacuum apparatus to the center of the injection tree at the top of the model.
c) Be sure that all three injection wells are exposed to vacuum by opening the appropriate valves. **Caution**: be sure all production valves are closed to the atmosphere.
d) Vacuum the model for approximately 24 hours.
e) Disconnect the vacuum apparatus.
f) Fill a 2000 ml graduated cylinder with exactly 2000 ml of brine.
g) The model must now be saturated with brine. Follow steps 2.3.2 f) - h) using the center production valve with the other wells open to the center production valve, ie: want the brine to flow into the model via all three production wells.
h) The pore volume is the volume of brine drawn into the model.
i) The model is now ready for pressure testing and permeability determination.

5.2.2 Wet Pack Pressure Test

~ Pressure testing is carried out in the wet pack before the pore volume is determined.

~ Essentially the same procedure is used to pressure test the dry pack after the pore volume has been determined.
~ The Milroyal pump is used for this process.

a) Rotate the model so that the flange side is facing forward.
b) Connect the steel braided line with the q/c's to the flange side center valve and to the injection "T". The Milroyal pump will be used to perform the pressure test.
c) Flush the Milroyal pump and all connecting lines, including the steel braided line, with distilled water which will be used to pressure test the model since it is presently saturated with distilled water.
d) Direct the flow of distilled water into the model through all three wells in the flange cover with all valves on the injection tree being closed.
e) Pressurize the model to approximately 7.0 MPa. **Caution**: the pump capacity must be set below 10% or the pressure will build up too quickly.
f) Visually inspect all lines and connections as well as the flange cover for any signs of leaks.
g) If any leaks are found, proceed to tighten the appropriate connections and/or flange bolts.
h) After all leaks have been found, pressurize the model to 7.0 MPa and watch the pressure gauge for a few minutes to see if the pressure is dropping or remaining constant.
i) When no leaks are visible and the pressure remains constant, with the system closed, then the pressure must be released.
j) The pressure in the model is released by closing the injection valve and partially opening the production valve until the pressure in the model has been released.

5.2.3 Wet Pack Procedure

~ This is the most common method used for determining the pore volume of the 2-D model.
~ The pore volume is determined by miscibly displacing the distilled water presently in the model by the more dense brine.
~ The constant rate pump is used in this process.

a) Rotate the model so the flange side is facing down.
b) Connect the steel braided with the q/c's line to the center valve on the flange cover, with the other wells open to the center, and the other end connected to the injection "T" at the top of the model.
c) Set the constant rate pump to 616 cm^3/hr and flush all lines with brine. After flushing the lines make sure the constant rate pump is full.
d) The brine is injected at the bottom of the model and the distilled water is produced at the top of the model see Figure E5-3.

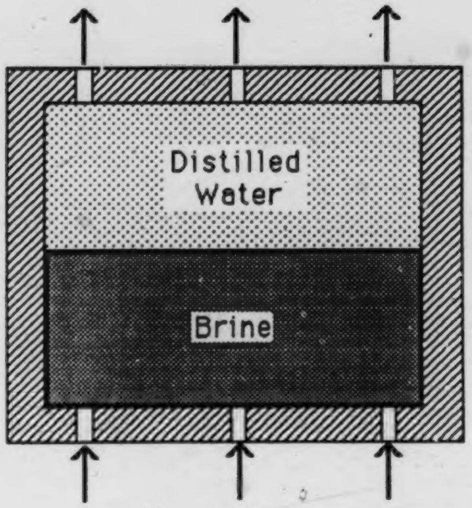


Figure E5-3. 2-D Model Wet Packing Procedure

e) Start the constant rate pump and begin injecting brine into the model through all three wells. Produce the distilled water through all three wells from the center valve only.

f) The first 1200 ml of water produced will be pure distilled water and only a single refractive index [RI] measurement is required. This RI corresponds to 100% distilled water. Be sure to record the exact volume of water produced.

g) After the first 1200 ml of water has been produced, begin to measure the RI {4 decimals} for every 100 ml sample collected {use small neck 100 ml graduated cylinders}. Record the RI along with the cumulative volume produced on the data sheet.

h) Continue measuring the RI for each 100 ml sample until a constant value corresponding to that of brine is reached. At this point the model is saturated 100% with brine.

~ Note: it is critical that the RI be recorded along with the cumulative volume of water produced.
~ Hints when operating the refractometer

(i) Always wipe surface of plates clean and dry
(ii) Clean plates with distilled water between measurements
(iii) Read RI to four decimal places ie:estimate last decimal

(iv) Keep plates dry when not in use

5.2.4 Pore Volume Determination

~ Bulk volume of cavity = 4871.0 cm^3
~ The pore volume is calculated utilizing graphical methods.

a) Construct a plot of refractive index [RI] verses percent brine in solution using the appropriate maximum and minimum on the refractive index scale .
b) Plot the RI of distilled water corresponding to 0% brine in solution and the RI of brine corresponding to 100% brine in solution. Join the two end points with a straight line, see Figure E5-4.
c) From the RI measured determine the corresponding percent brine in solution.

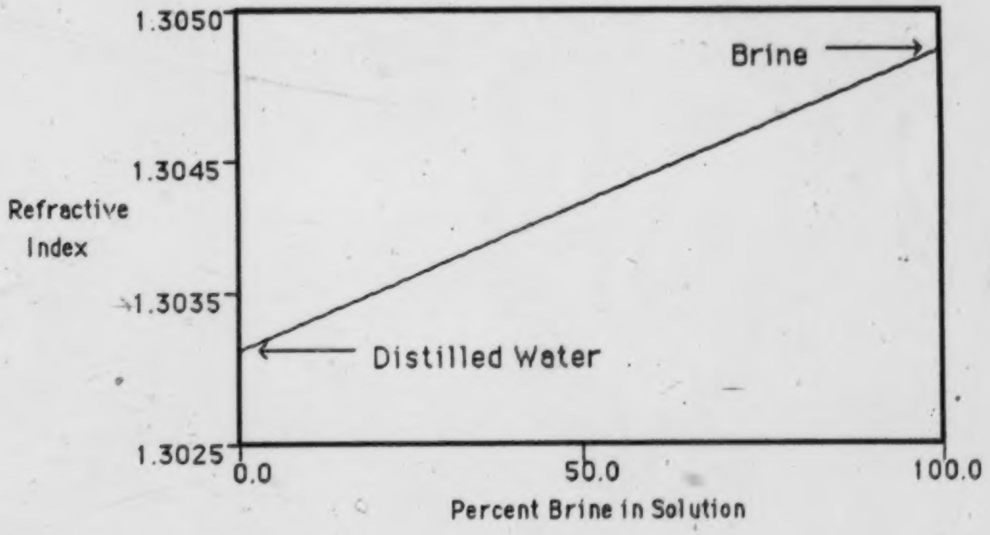


Figure E5-4. 2-D Model Fraction of Brine in Solution

d) Construct a plot of Percent Brine in Solution verses Cumulative Volume Produced using the data obtained from Figure E5-4.
e) Join the data points with a smooth curve between the 0.0% and 100.0% end points of the percent brine in solution curve.
f) The pore volume is the cumulative volume produced when Area A = Area B, see Figure E5-5. The porosity is the pore volume divided by the bulk volume.

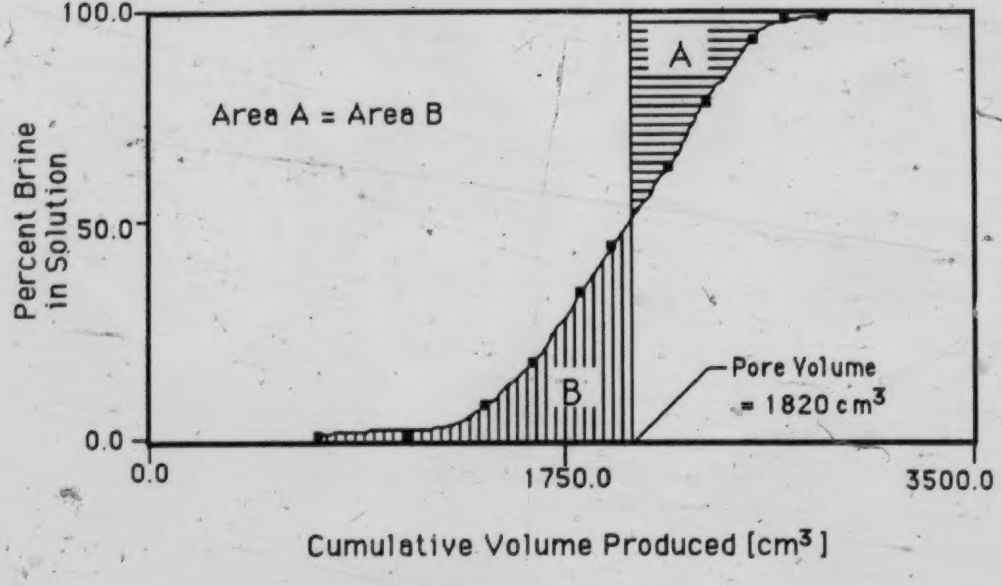


Figure E5-5. 2-D Model Pore Volume Determination

5.3 Permeability Determination

~ This procedure is almost identical to that of the linear core.

~ The permeability is measured diagonally across the model simulating a quarter of a five spot well pattern, see Figure E5-6.

~ Brine is used for the permeability measurement.

a) Follow steps 2.4.1 a) - d) to prepare the vacuum apparatus for the permeability procedure.
b) Rotate the model so that the flange side is facing forward.
c) Connect the steel braided line from the bottom of the tank on the VA to the injection valve on the top far left hand side of the model using the q/c's. Note: make sure only this well is injecting by closing the appropriate valves.
d) Connect a short portion of 1/4 inch plastic tubing to the bottom far right hand side producing well. Note: make sure only this well is producing by closing the appropriate valves.

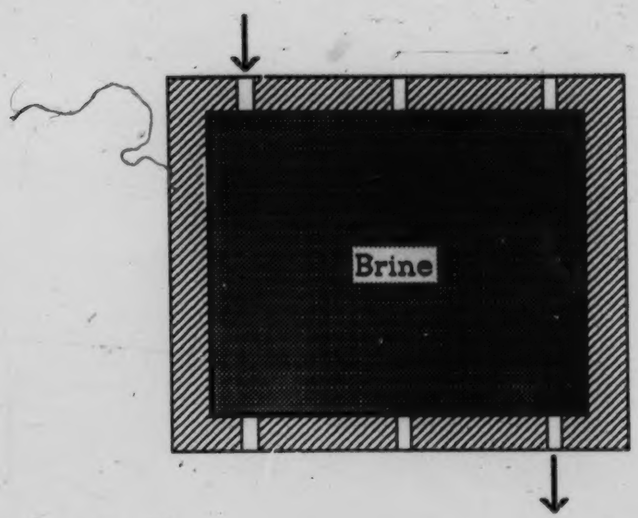


Figure E5-6. 2-D Model Permeability Determination

e) Follow steps 2.4.2 c) - f) to determine the permeability parameters.
f) The absolute permeability [K] is calculated as follows:

$$K = 6.0687386 \bullet (q / \Delta P)$$

g) The values of K are arithmetically averaged out over the entire range of ΔP's unless some of them, especially at low ΔP, contradict the others, in this case these contradictory values should be ignored.

~ If a consistent set of results are obtained, then the permeability determination is complete.

5.4 Oil Saturation of Model

~ Stable displacement of water by oil, of a lesser density, requires the oil be injected in the top of the model and the brine be produced from the bottom.

5.4.1 Saturation Procedure

a) Rotate model so the flange is facing down.
b) All production lines must first be cleaned, this is accomplished by flushing with Varsol from the squeeze bottle.
c) Oil will be injected through all three injection wells from the Milroyal pump (set capacity of pump at 7.0%) and fluids will be

produced from all three production wells through the center valve, see Figure E5-7.

d) Connect a small piece of tubing from the center production valve extending out so that the produced fluids may be collected in graduated cylinders positioned in front of the model.

e) Follow steps 2.5.1 a) - m).

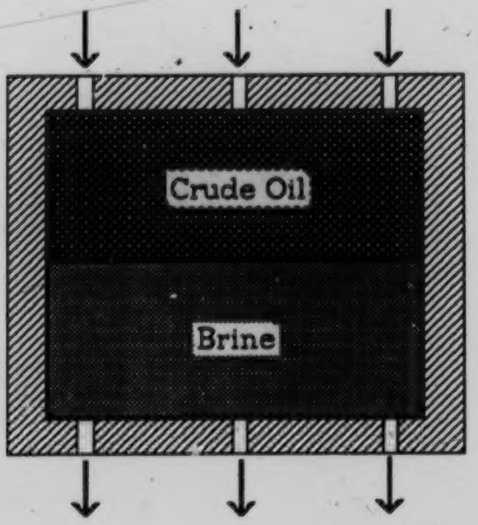


Figure E5-7. 2-D Model Oil Saturation

5.4.2 Saturation Determination

~ The Saturation determination in the 2-D model is almost identical to that of the linear core except that corrections are not needed for fittings and connections in the 2-D model because the line volumes are relatively small.

~ Oil saturation determination is very important for further analysis of results of each run.

~ Initially the model is saturated 100% with brine.

~ Oil saturation is given the symbol: S_o

~ Oil saturation at the experimental pressure is given by the symbol: S_{om}

~ Connate water saturation is given the symbol: S_{wc}

~ Hydrocarbon pore volume is given the symbol: HCPV

a) A rough estimate of the oil saturation is made using the volume of oil injected.

$$S_o = \underline{[\text{ Oil Injected - Oil Produced }]\ [cm^3]}$$

$$\text{Pore Volume [cm}^3]$$

S_{om} = Numerator + Additional Volume of Oil Required to Raise Pressure

b) A more accurate estimate of oil saturation is made using the volume of brine produced. Initially the core is assumed to be 100% saturated with brine therefore occupying all of the pore space. The volume of oil in the model is equal to the volume of water displaced.

$$S_o = \frac{\text{Volume Brine Produced [cm}^3]}{\text{Pore Volume [cm}^3]}$$

S_{om} = Numerator + Additional Volume of Oil Required to Raise Pressure

$$S_{wc} = 1.0 - S_o$$

$$= \frac{\{\text{Pore Volume - Brine Produced}\}\ [\text{cm}^3]}{\text{Pore Volume [cm}^3]}$$

~ The second calculation for connate water saturation is used to check the validity of the first calculation.
~ The volume of brine /oil produced is determined by separating the effluents in the centrifuge.

$$\text{HCPV} = S_{om} \bullet \text{Pore Volume [cm}^3]$$

5.5 Experimental Procedures

~ The experimental procedures carried out on the 2-D model are very similar to those used on the linear model.
~ The initial oil saturation must be known before any type of displacement is carried out on the model.

5.5.1 Brineflood

~ Brine flooding is only carried out on the initial runs so that CO_2 recovery may be compared to conventional methods on a relative basis, as well as after the WAG process.
~ The brine to be used in all runs is that which was supplied by Husky Oil and can be found in the five gallon white pails.

a) Rotate the model so the flange side is facing forward.
b) The brine will be pumped from the constant rate pumps at the next highest rate nearest to the scaled rate calculated on the data sheet.

c) All lines must first be flushed of all other fluids which may be present, this is accomplished by pumping first Varsol, and then distilled water throughout the tubing system.

d) Once all of the lines have been cleaned, the brine should be circulated throughout the system.

e) The constant rate pump must then be filled with brine by closing all the external valves and redirecting the brine from the Milroyal pump into the constant rate pump.

f) After the constant rate pump is full, the valves should be redirected into the model with the injection valve nearest the model **closed.**

g) The lines must now be flushed with the brine from the pump, this is done by opening the bleed side of the 3-way valve at the top of the model and cranking the constant rate pump by hand until a clear stream of brine is seen.

h) The injection line must now be bled nearest the model. This is accomplished by redirecting the flow to the bleed side of the valve. When a clear stream of brine appears, turn the valve to the **off** position.

i) The injection lines must now be pressured to the same pressure that exists in the model ie: experimental pressure. This is done by cranking the constant rate pump by hand and engaging it at a pressure near or below the experimental pressure.

j) The pump may then be turned on in short intervals to raise the pressure in the line to the desired experimental pressure.

k) When the pressure in the injection lines are near the experimental pressure open the injection valve nearest the model. If the pressures in the lines and in the model are approximately the same the injection pressure gauge will only move slightly. If the injection pressure gauge moves dramatically, either the model or the injection line must be brought up to the experimental pressure.

l) Record the initial "reading" on the constant rate brine pump (2-decimals), the DTM (3-decimals), as well as the initial production and injection pressures.

m) Install a 100 ml graduated cylinder to collect the effluents. Initially only oil will be produced. Continue using 100 ml graduated cylinders until brine breakthrough occurs, then use 250 ml graduated cylinders.

n) Turn the constant rate pump on, making sure the CO_2 pump is disengaged, and open the production valve. Note: make sure only the production well on the right hand side is open. The Back Pressure Regulator (BPR) should initially be set approximately half-way.

o) Initially the production pressure will have to be monitored frequently and adjusted accordingly, with the BPR, to the experimental pressure. This will usually take a few re-adjustments.

p) Record, with each change of cylinder, all values required on the data sheet. Before stopping the pump, the production and injection pressures should be recorded. As soon as the pump is turned off the production valve nearest the BPR should be turned off. Reverse the order after the graduated cylinder has been changed.
q) Before the pump has reached its maximum (≈490 cm^3) it must be refilled (see step 3.1 d)
r) Continue injecting brine until a producing WOR of approximately 20:1 is reached. At this point the experiment is complete.

5.5.2 CO_2 WAG Process

~ The first slug in the WAG process is CO_2
~ Both the gas and brine constant rate pumps should be full before preceding with the experiment.
~ See section 3.2.1 for the preliminary CO_2 calculations.

a) The injection lines must first be pressured to the model pressure. This is done by cranking the constant rate gas pump by hand, with the inlet valve closed, until the pressure is slightly above the experimental pressure.
b) Because the gas compresses so much, only a small volume of gas may be left in the pump after the experimental pressure is reached. If this is the case, the pump will have to be filled again before the run may proceed. This is done by closing the exit valve at the pump, disengaging, and opening the fill valve connected to the carbon dioxide tank.
c) Remember to reverse the procedure after the pump is full.
d) Record the initial "reading" on the constant rate pump (2-decimals), the DTM (3-decimals), as well as the initial production and injection pressures. Set the stopper on the pump approximately 5.0 cm^3 before the desired slug size volume.
e) See step 3.1.2 b). Set the rate on the pumps (see pump chart at back).
f) Turn the CO_2 constant rate pump on making sure the brine pump is disengaged, and open both production valves.
g) See steps 3.1.2 d) - f) ;
h) When the pump shuts off due to the stopper turn it back on again by disengaging the stopper and pushing the restart button. Record the injection and production pressures and shut pump off manually at the desired slug size.
i) Close the production valve nearest the BPR as well as the injection valve nearest the model. Record the final "reading" as well as the DTM for produced gas. Close the main gas valve at the 2-D model, disengage the CO_2 pump, and partially release the pressure by cranking the pump counterclock-wise. The model is now ready for a brine slug.
j) Turn the main gas valve towards the brine injection line.

k) See steps 3.1.1 a) - e) and steps 3.1.2 a) - e) .
l) Remember to set the stopper on the brine pump approximately 5.0 cm^3 before the desired slug size volume.

~ At this point the procedure is altered back to the gas slug until 10 slugs of gas and 10 slugs of brine have been injected.
~ Continue injecting brine until a producing WOR of approximately 20:1 has been reached.

5.5.3 Blowdown Recovery

~ Blowdown recovery procedures take place after a producing WOR of approximately 20:1 has been reached.
~ Blowdown recovery is due to the pressure release in the model when gradually opened to atmospheric conditions.

a) Install a 250 ml graduated cylinder to collect the blowdown effluents and record the reading on the DTM.
b) Close the injection valve nearest the model.
c) With the production valves open, slowly begin to open the BPR (counterclock-wise) in small increments and let the pressure subside.
d) After the pressure has subsided, open the BPR another small increment.
e) Repeat steps c) - d) until the production pressure has been reduced to approximately 0.2 MPa. At this point, open the BPR fully and let the model stand for approximately 5 hours.
f) Record the final reading on the DTM and perform the analysis on the blowdown effluent.

~ At this point the experiment is complete.

5.6 Cleanup Procedures

~ Do not begin the cleanup procedure until all of the effluent have been analyzed and recorded.
~ Cleanup is extremely important to all subsequent runs.
~ Model pressure is released during blowdown recovery.

5.6.1 Cavity Cleaning

~ Only Varsol is used when cleaning the cavity.
~ All precautions should be taken to prevent oil and sand from falling on the floor.

a) Disconnect the injection line from the 3-way valve at the top of the model, as well, disconnect the short production line from the "T" at the front of the apparatus.
b) Rotate the model so the flange is facing up. Place old newspapers all around, and on, the apparatus to keep the floor clean.

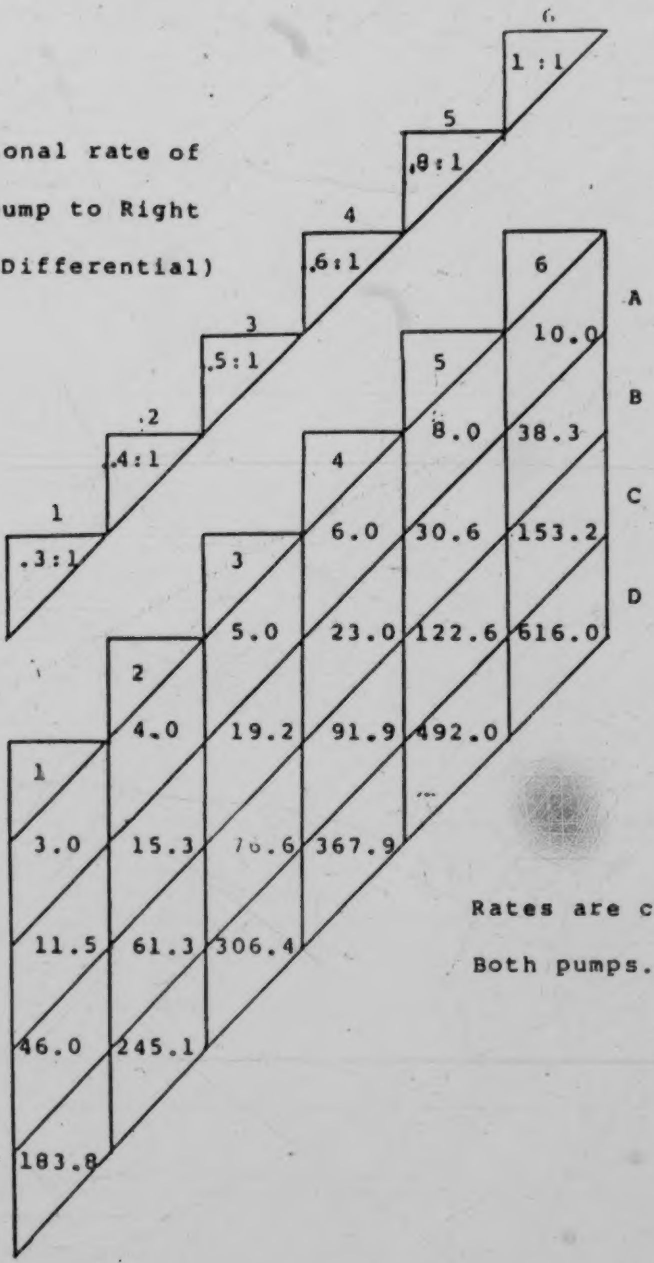
c) The injection tree at the back of the model must now be replaced with the dummy wells.
d) Remove the flange bolts and flange from the model making sure not to destroy the rubber sealing ring.
e) Rotate the model so the cavity opening is facing forward. Without the flange in place the model is bottom heavy, therefore a small piece of wood behind the model is needed to keep the model in the horizontal position.
f) Place a open green garbage bag below the opening of the cavity to collect the oil and sand.
g) Begin to scrape the sand into the garbage bag with the long steel scraper found in the fume hood. Continue to scrape the sand from the cavity until most of the sand has been removed (use the hooked end in the corners).
h) With the cavity almost clean, remove and tie the garbage bag and rotate the model so the cavity opening is facing up.
i) Place the large tin waste pan, found at the bottom of the fume hood, below the front of the model. This is to collect the dirty Varsol as it falls out of the model.
j) To remove the remaining sand and oil, spray the walls of the cavity with Varsol and scrub the walls with the long cloth brush.
k) Rotate the model quickly so the dirty Varsol runs out of the cavity and into the tin waste pan. Rotate the model back to its original position.
l) Repeat steps j) - k) until the cavity is clean.
m) Rotate the model so the cavity opening is facing forward ie: use the small piece of wood behind the model.
n) The injection ports must now be cleaned. This is accomplished by removing the dummy wells and flushing the ports with Varsol until clean.
o) The cavity must now be dried. This is accomplished by placing a high pressure air line in the cavity and blowing air for several hours.

5.6.2 Tubing Cleaning

~ Flush disconnected lines with toluene and acetone and blow air through immediately afterwards to dry.
~ Clean all other lines by pumping Varsol through followed by distilled water.
~ **Caution**: remember to close valves nearest the Heise gauges before cleaning.

~ The model is now ready to be packed for the next run.

Fractional rate of
Left pump to Right
pump (Differential)



	1	2	3	4	5	6
	.3:1	.4:1	.5:1	.6:1	.8:1	1 :1
A	3.0	4.0	5.0	6.0	8.0	10.0
B	11.5	15.3	19.2	23.0	30.6	38.3
C	46.0	61.3	76.6	91.9	122.6	153.2
D	183.8	245.1	306.4	367.9	492.0	616.0

Rates are cm^3/hr for
Both pumps.

Ratings For: - 500 cm^3/pump
- @ 40 RPM input to gear box
- Constant Rate